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# A COMPREHENSIVE ANALYSIS OF THE OIL FIELDS OF THE NORTH SLOPE OF ALASKA, THEIR USE AS ANALOGS, RECENT EXPLORATION, AND FORECASTED ROYALTY AND PRODUCTION TAX REVENUE

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## ABSTRACT

Revenues from petroleum production supply most of the revenue for unrestricted general funds for the State of Alaska. As such, variations in the price of oil, decline from existing production and new developments greatly affect the money available for the state to spend on everything from roads to education. This study reviewed all producing oil fields on the North Slope, characterized their reservoir performance and forecasted future production. This was coupled with analysis of recent exploration discoveries and ongoing project developments to forecast future North Slope production and create potential royalty and production tax revenue forecasts. After 40 years of production, Prudhoe Bay remains the dominant field on the North Slope, accounting for 45% of current production. Relatively large changes in the non-anchor field pools are only able to change North Slope production by a couple of percent due to the nature of their size compared to Prudhoe Bay, Kuparuk and Alpine. New developments however, are able to materially contribute to changes in North Slope production if they are large enough. With continued activity in the many fields, creating an accurate forecast is challenging, however, without new developments, the Trans Alaska Pipeline will need to make changes to accommodate low flow rates. Currently identified new developments have the potential to extend current production rates 10-20 years. Some of these announced developments and discoveries have announced productivity rates that are not realistic compared to analog well performance, and will likely require many more wells to achieve the announced rates and volumes.

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## DISCLAIMER

The data from this study has been taken from publicly available data and does not include proprietary or confidential information available to North Slope operators, owners, or government agencies. All analysis, opinions, and conclusions presented in this project are that of the author and do not represent the views, opinions, or positions of any operator or working interest owner of the fields analysed in this study. The author assumes no liability for decisions that utilize the data or analysis presented here.

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## 1. INTRODUCTION

The intent of this study is twofold: The primary goal of the study is a review of North Slope reservoirs and to compile correlations and trends that can be used as analogs to predict future development performance. The second goal is to use this field analysis, coupled with the current known exploration development timelines, to predict the potential revenue that will potentially be obtained by the State of Alaska through royalties and production taxes. Much of the analysis in this report is taken from public data, some of which is given in ranges and sometimes varies by source. When ranges of data are given, the midpoint of the range was used in calculating numbers such as permeability, net thickness, and stock tank oil initially in place (STOIIP). When numbers varied from source to source, preference was given to numbers reported by the operator, then by date of report. An example of this would be the STOIIP of the Aurora field, which in Conservation Order 457 is reported to be between 110-146 MMSTB, whereas the 2011 publication “BP in Alaska” factbook lists it as 190 MMSTB (BP Exploration (Alaska) Inc., 2011). Similarly, BP in that factbook lists the Lisburne oil originally in place to be 2.4 billion barrels, while the joint ConocoPhillips and BP publication “Arctic Energy” lists it at 1.8 billion barrels (BP Exploration (Alaska) Inc.; ConocoPhillips Alaska, 2006). All production and injection data was taken from the Alaska Oil and Gas Conservation Commission, as well as most reservoir properties. When a range in reservoir properties was given, but previously a single value had been reported, that value was used instead of the midpoint of the range. Although previously regularly updated on the AOGCC website, available pool statics have not been updated since 2012. Additionally, quantity and quality of public data on each field varied significantly, depending on the size, age, and operator. Production data for this study was sourced from the AOGCC, through July 2017. This study utilized an Access database and VBA enhanced Excel worksheets to develop the field trend plots. Additionally, many of the plots in this study utilized the statistical graphing software Spotfire. Individual field production forecasts were interpreted using Landmark’s Dynamic Surveillance System software.

## 2. NORTH SLOPE GEOLOGY

The North Slope of Alaska has had a complex history with changing depositional directions and paleo shorelines. Producing reservoirs in the central North Slope are predominantly fluviially dominant or near shore marine clastic sandstones, with the exception of the Lisburne formation, which is a carbonate. Most fields fall into a series of regionally correlative formations such as the Ivishak, Kuparuk, and Schrader Bluff sands as seen in Figure 1. Although individual field properties vary, relative trends can be derived by comparing similar fields with fairly high confidence when planning new developments. With the recent discoveries of Willow, Horseshoe and Pikka there has been excitement in the Nanushuk formation and the potential for other reservoirs yet to be found in other clinoforms across the North Slope.

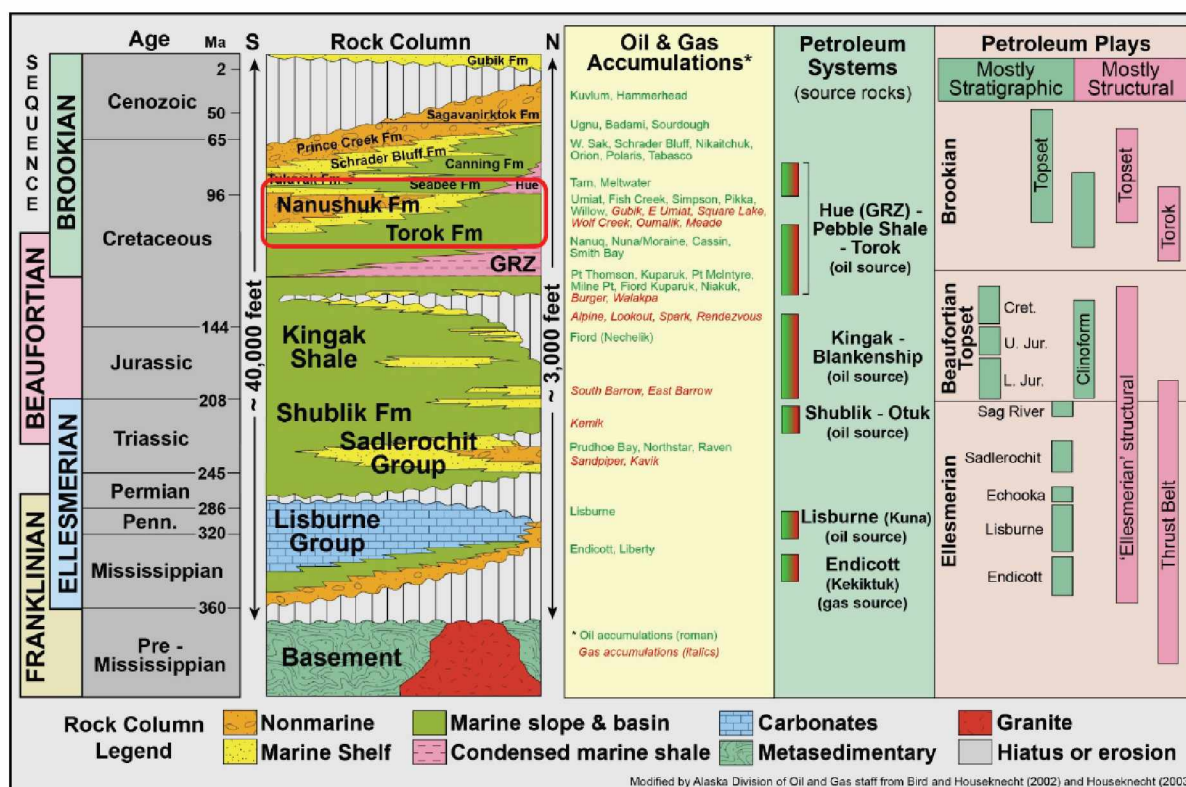


FIGURE 1: NORTH SLOPE STRATIGRAPHIC COLUMN (ALASKA DEPARTMENT OF NATURAL RESOURCES, DOG, 2017)

### 3. OVERVIEW OF NORTH SLOPE PRODUCTION

Production from the North Slope through the Trans Alaska Pipeline (TAPS) began in June 1977, producing from the giant field Prudhoe Bay. Developments at Kuparuk, Endicott, Milne, and Lisburne followed in the next ten years with production peaking at over 2 million barrels of oil per day. From 1998-2000, developments at Badami, Alpine, and Northstar came online. In the past ten years developments at Ooguruk, Nikaitchuq, and Pt. Thomson have come online, averaging a combined 40,000 bopd. Throughout the years additional smaller satellite fields came online contributing greatly to the total production. It is a testament to the size and productivity of Prudhoe Bay that the initial participating area still accounts for 45% of North Slope production, even though there are forty producing pools. Supplemental North Slope field production charts can be found in the Appendix; Figure 287-Figure 291.

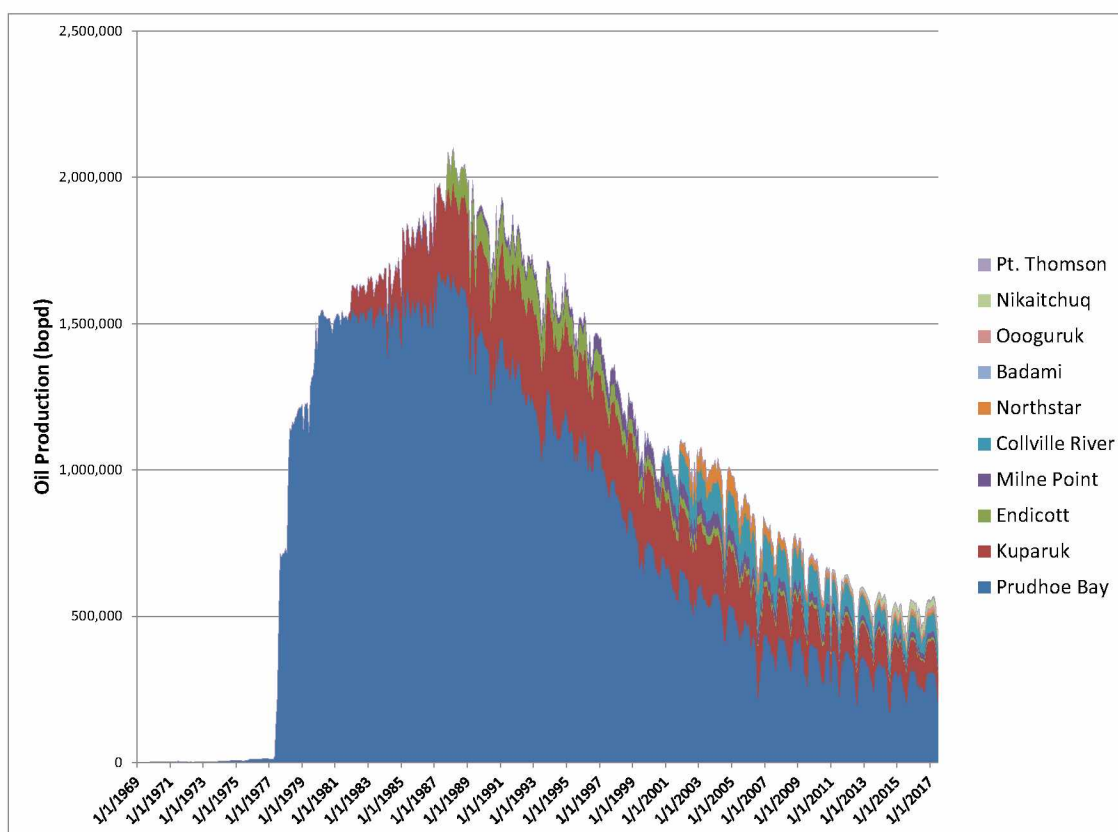


FIGURE 2: NORTH SLOPE PRODUCTION BY UNIT

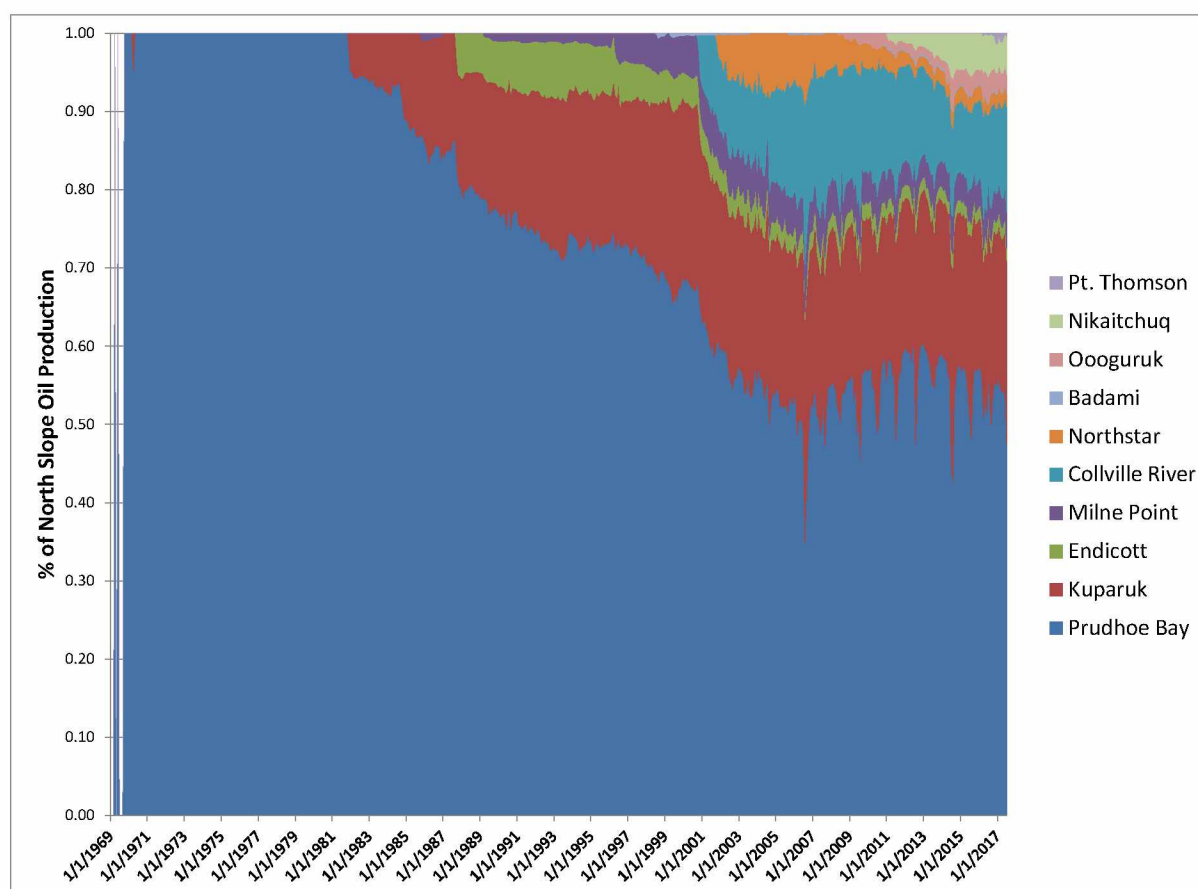


FIGURE 3: PERCENTAGE OF NORTH SLOPE PRODUCTION BY UNIT

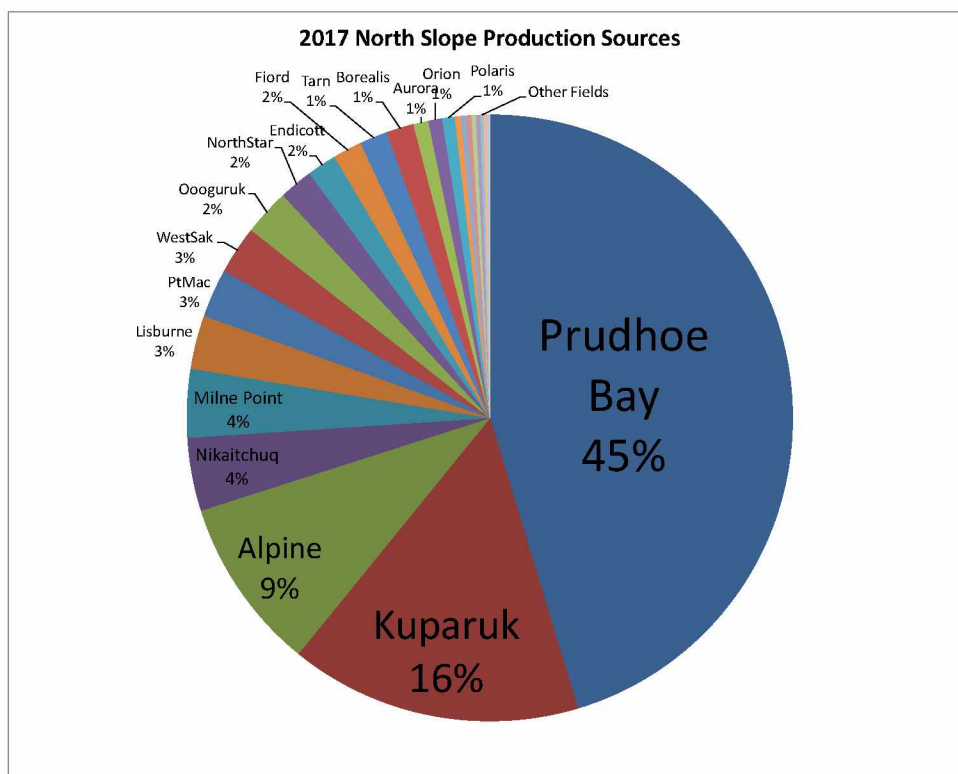


FIGURE 4: FIRST HALF 2017 NORTH SLOPE PRODUCTION SOURCES BY FIELD

## 4. NGL PRODUCTION

For some of the fields on the North Slope, NGL production is reported separately from oil production. This is true for Prudhoe Bay, North Star, Endicott, Sag Delta North, and the fields of GPMA (Lisburne, Pt. McIntyre, Niakuk, Raven, North Prudhoe and West Beach). Kuparuk reported producing 3.3 million barrels of NGLs between 1985 and 1988, but has not reported separate NGL production since. Northstar began reporting NGL production in November 2014. NGL blending is often limited by vapor pressure limitations to meet Alyeska specifications at Pump Station 1. NGL forecasts for this study were created based on a percentage of oil production of the associated pools. In 2016, NGL production averaged 44.7 mbd and the 16.36 million barrels produced the accounted for 9.4% of total North Slope production. Individual field NGL profiles can be found in the Appendix, Figure 292-Figure 303.

TABLE 1: AVERAGE RECENT NGL PERCENTAGE OF TOTAL OIL PRODUCTION

Prudhoe Bay	16.6%
Lisburne	11.7%
Pt. McIntyre	7.3%
West Beach	11.5%
North Prudhoe	3.5%
Niakuk	2.0%
Raven	5.1%
Northstar	39.6%
Northstar Kuparuk	21.1%
Endicott	11.6%
Sag Delta North	0.5%

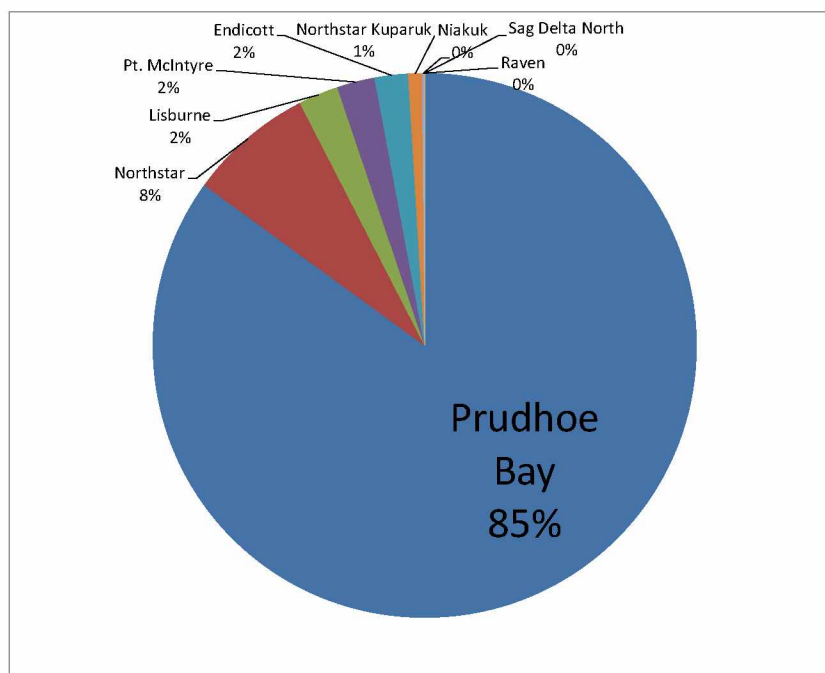


FIGURE 5: SOURCES OF 2016 NORTH SLOPE NGL PRODUCTION

## 5. NORTH SLOPE RESERVOIR TRENDS

Analog field performance is one of the best tools for predicting how a new development, or a new well in an existing development will perform. When a press release for a discovery or a new field is published, there is often little associated data with the announcement. It is important to take a step back and analyse what parameters are needed for a field to produce 10 million or 10 billion barrels, the feasibility for fields to deliver 10,000 barrels per day or 100,000, and how many wells are needed to deliver those rates and volumes. Exploration wells typically target the places in a reservoir with the highest chance of success, and it is common for the earliest wells to have the best reservoir properties. These early wells also have the advantage of original reservoir pressure and saturation, and minimal inter-well competition. Assuming every well in a development to have similar productivity of the exploration and appraisal wells is a great way to promote and market a field; however, it will lead to a development that does not deliver promised rates and volumes for the number of expected wells. Prudhoe Bay, with fifty years of continual drilling, is a great example of diminishing benefits of new wells, as the average well drilled today makes less than a million barrels whereas the early wells averaged over 20 million barrels a well. This is a great example of why early wells should not be the expectation of all wells, however, care should be used when using Prudhoe Bay as an analog from a development standpoint, as cum oil per well statistics for the field are dynamic and have been decreasing with time rather than increasing for many years due to continual development and the order of magnitude discrepancy in productivity of early wells to recently drilled wells. With the number of pools across the North Slope in various formations, a company can narrow the range of expected reservoir properties and well productivity by choosing appropriate analogs. To minimize the effects of reservoir size and development scheme, an attempt was made to compare the fields based on the number of development wells, including injectors. Producer:Injector ratio is an important factor that is often overlooked when describing well performance. It is common to say something along the lines of “the average well in this field will make a million barrels.” Often, this is said without the clarification of whether that is for the average producer, or the average of all wells drilled. The implications of this are that a field like developed like Alpine, which has a 1:1 Producer:Injector ratio and is developed in a line drive flood, if the average producer makes a million barrels, then the average total per well is actually 500,000 barrels (actual cum oil per well for Alpine is 2.7 MMBO). Similarly, if the average producer in a field developed like Pt. McIntyre were to make a million barrels, where



the wells are in inverted nine-spot patterns and has an average Producer:Injector ratio of 3:1, then the average production per well is 750,000 barrels (actual cum oil per well for Pt. McIntyre is 5.1 MMBO). With well costs on the North Slope being in the millions of dollars each, this difference impacts the overall project economics. Production statistics are also important in removing biases when analysing fields. For example, the Lisburne development is often considered a failure, as the field peaked at rates less than half of expectations, and drilling was stopped less than halfway through the initial development plan. Despite many of the wells being shut-in for a duration after the nearby prolific fields Pt. McIntyre and Niakuk began producing to their shared facility, it has averaged about 1.9 million barrels per well (mmbo/well). In comparison, the Kuparuk field has averaged 2.17 mmbo/well, and the Milne Point field, has averaged 0.5 mmbo/well in the Schrader Bluff formation, and 1.25 mmbo/well in the Kuparuk formation. Although drilling and other development costs are not addressed in this comparison, Lisburne has favorable recovery per well metrics compared to many other North Slope fields. For this study, the cumulative produced oil per well includes all wells drilled in the field regardless of production life, and is not reflective of the expected ultimate reserves (EUR) per well, but the total produced oil by July 2017. Many of the fields of the North Slope have good reservoir properties; however, none of them have averaged more than 6 mmbo/well, with the vast majority of the fields averaging between 0.5-1.5 mmbo/well. Additional figures on reservoir performance can be found in the Appendix in Figure 304 through Figure 325.

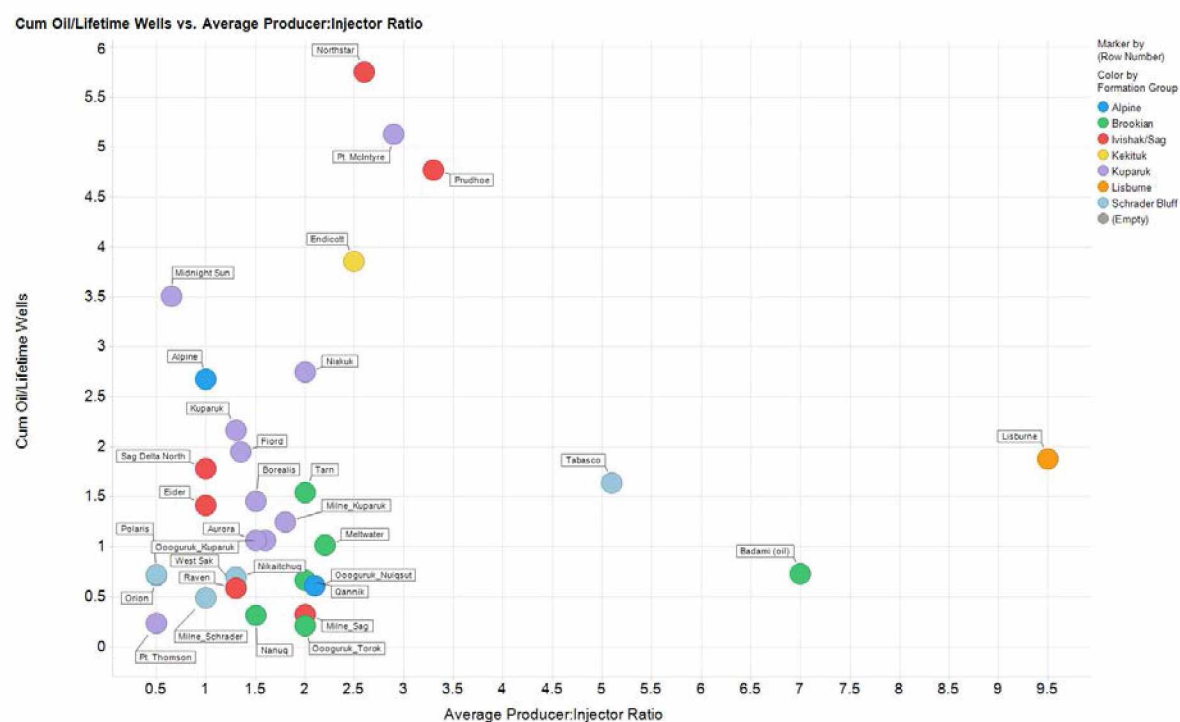


FIGURE 6: CUM OIL/LIFETIME WELLS (MMBO) VS AVERAGE PRODUCER:INJECTOR RATIO

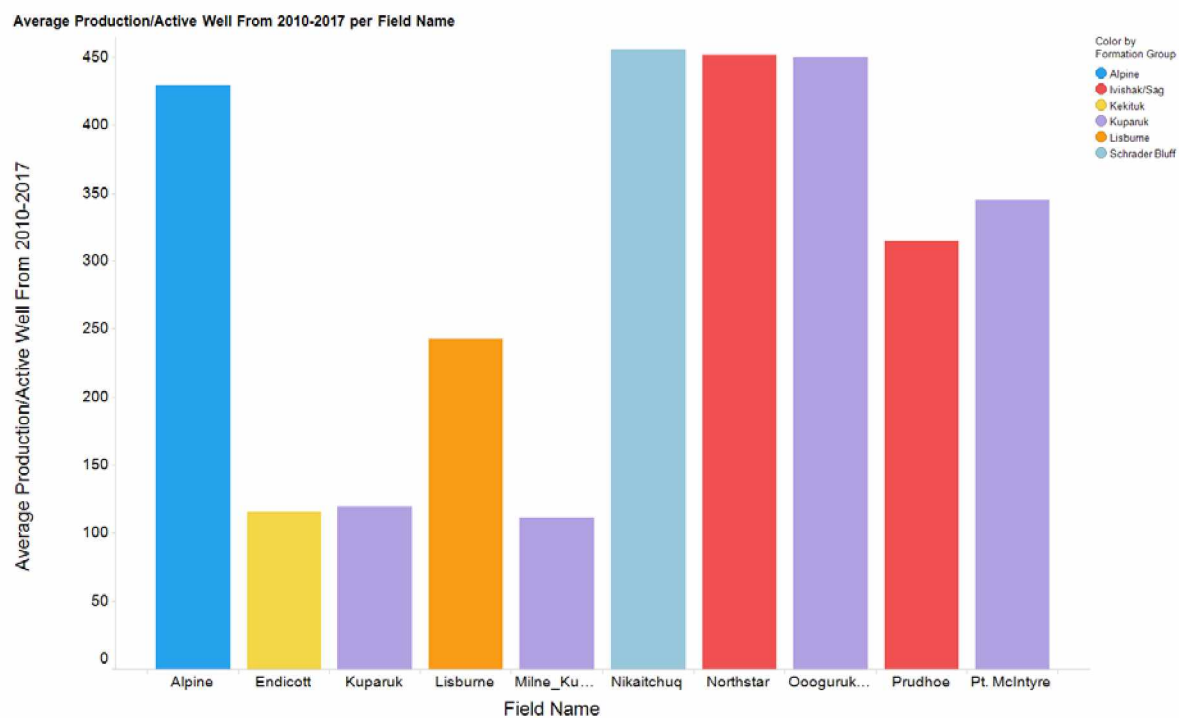


FIGURE 7: AVERAGE PRODUCTION/ACTIVE WELL FOR ANCHOR FIELDS FROM 2010-2017

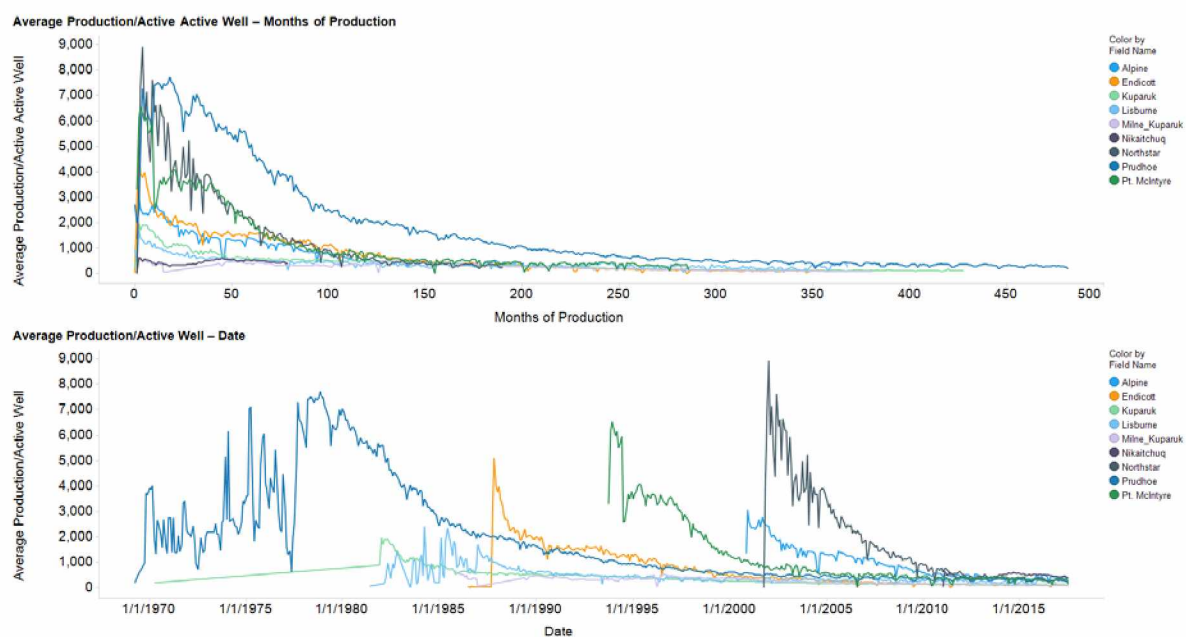


FIGURE 8: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) FOR ANCHOR FIELDS

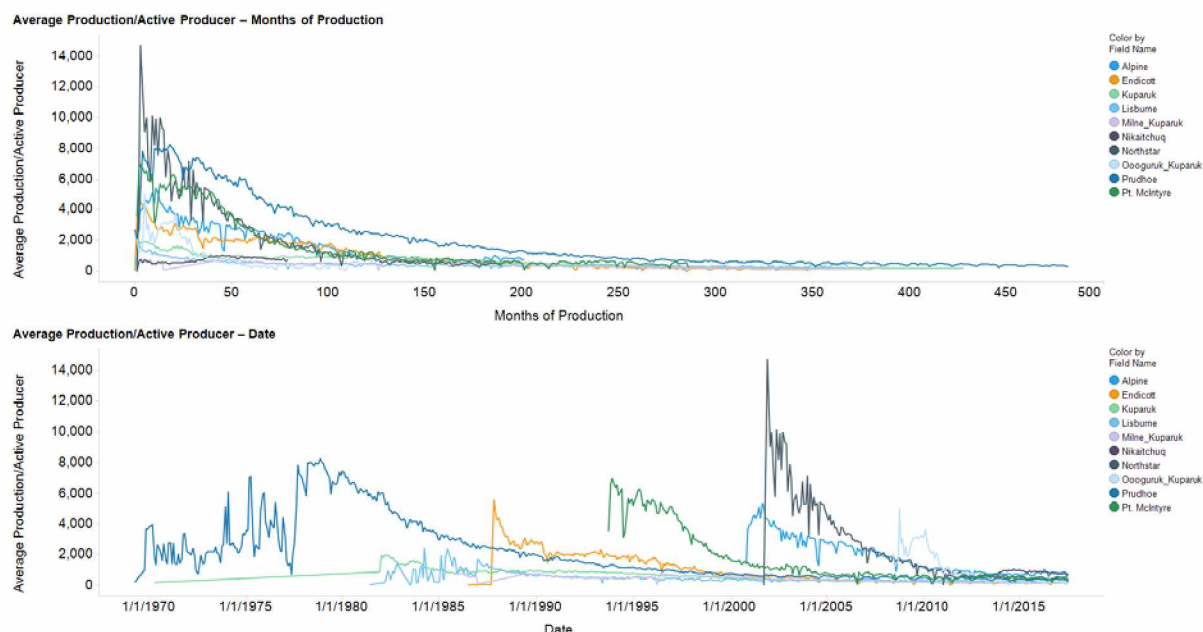


FIGURE 9: AVERAGE PRODUCTION/ACTIVE PRODUCER (BOPD/WELL) FOR ANCHOR FIELDS

Figure 10 depicts average production per active well in barrels of oil per day for fields that averaged more than 250 bopd/well. The top producing pools, Northstar Kuparuk, Oooguruk Nuiqsut and Nikaitchuq are relatively immature in their field development compared to most of the other fields. Additionally, Raven has a small pool with few wells and recently drilled a productive side-track.

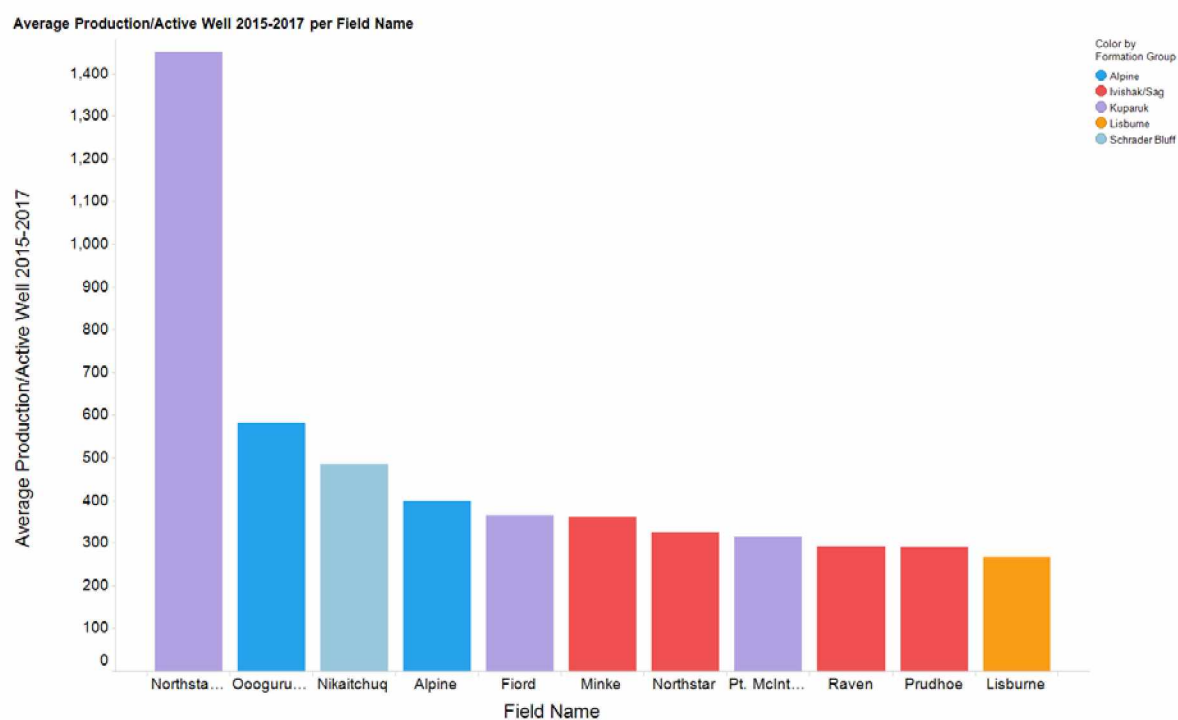


FIGURE 10: AVERAGE PRODUCTION/ACTIVE WELL 2015-2017, SELECTED FIELDS



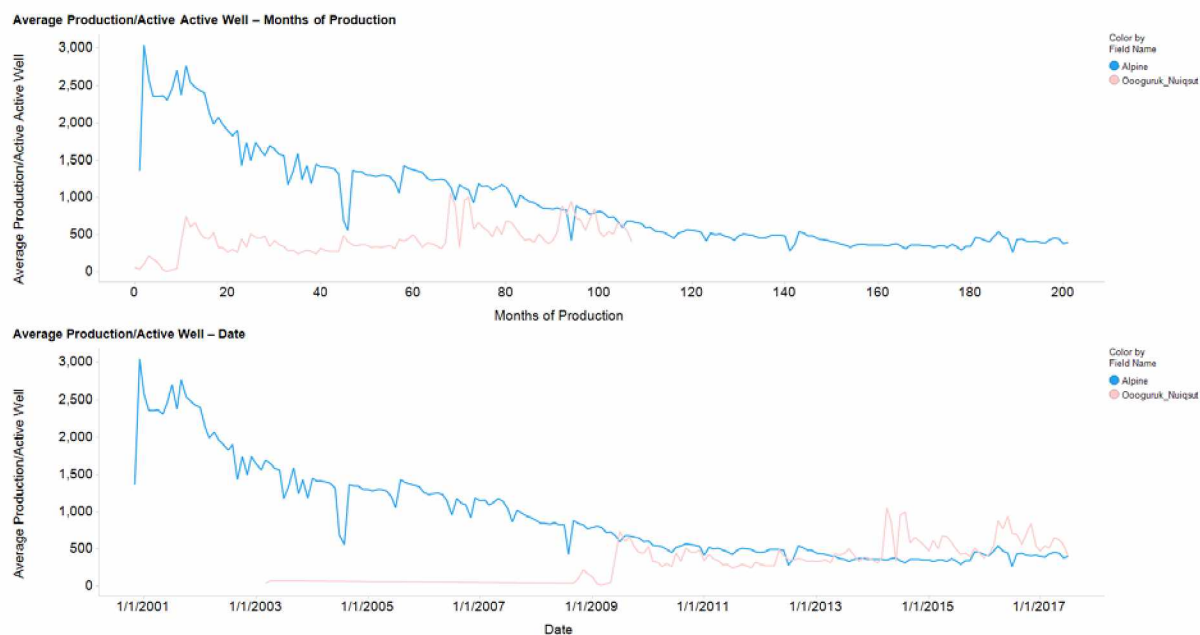


FIGURE 11: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) FIELDS WITH ALPINE LIKE FORMATION

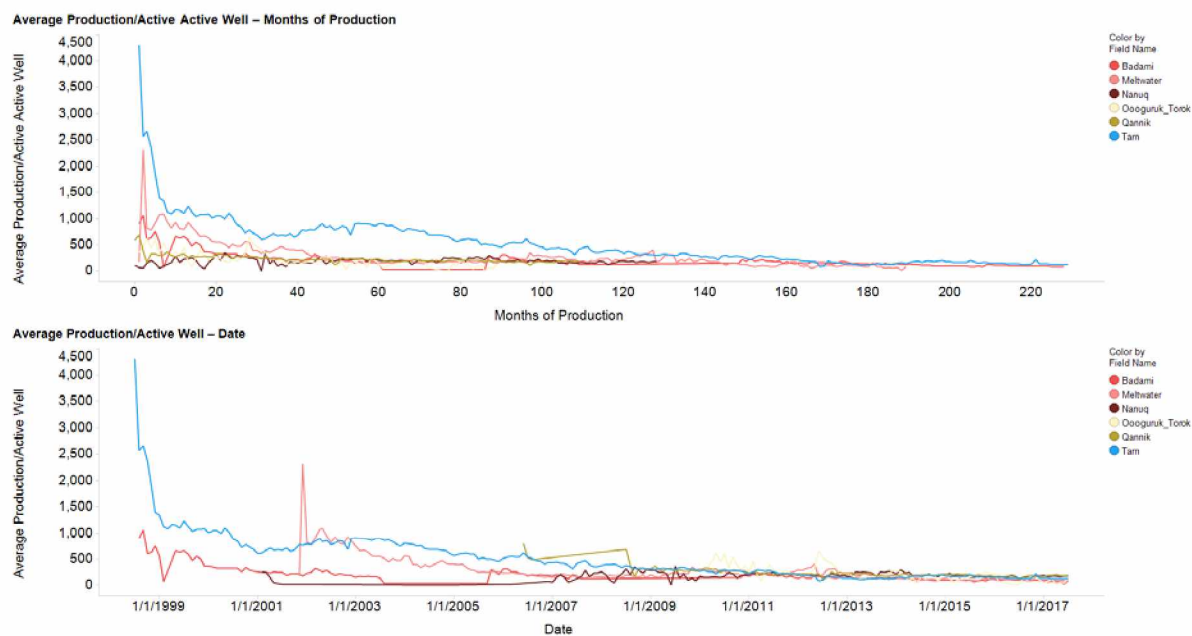


FIGURE 12: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) FIELDS WITH BROOKIAN FORMATION

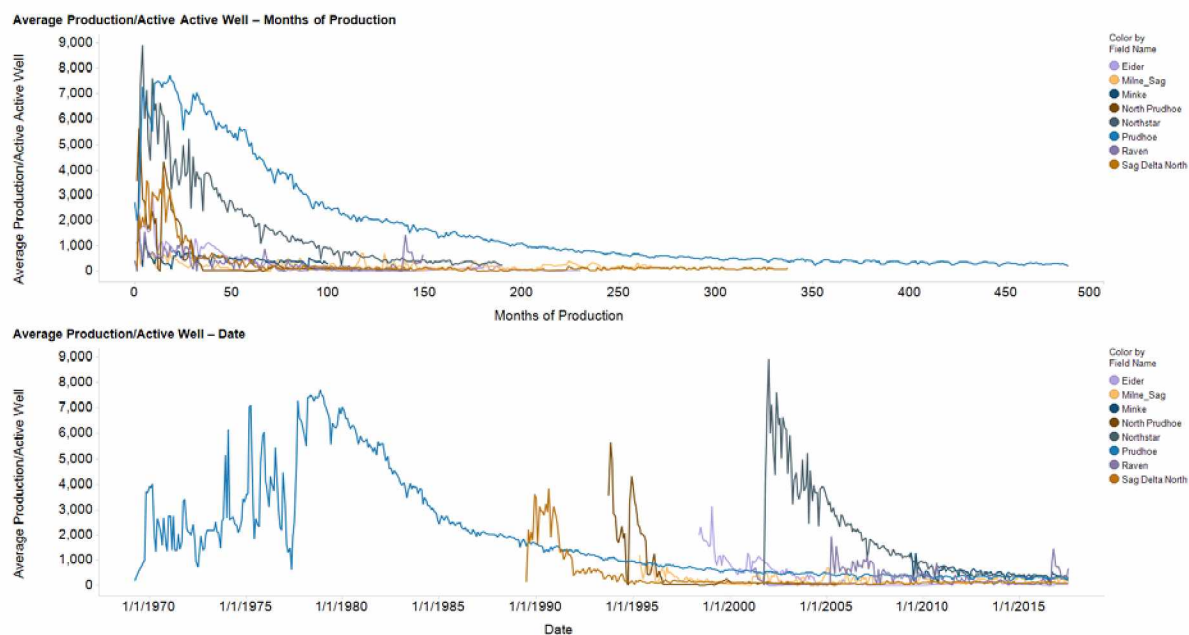


FIGURE 13: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) FIELDS WITH IVISHAK/SAG FORMATION

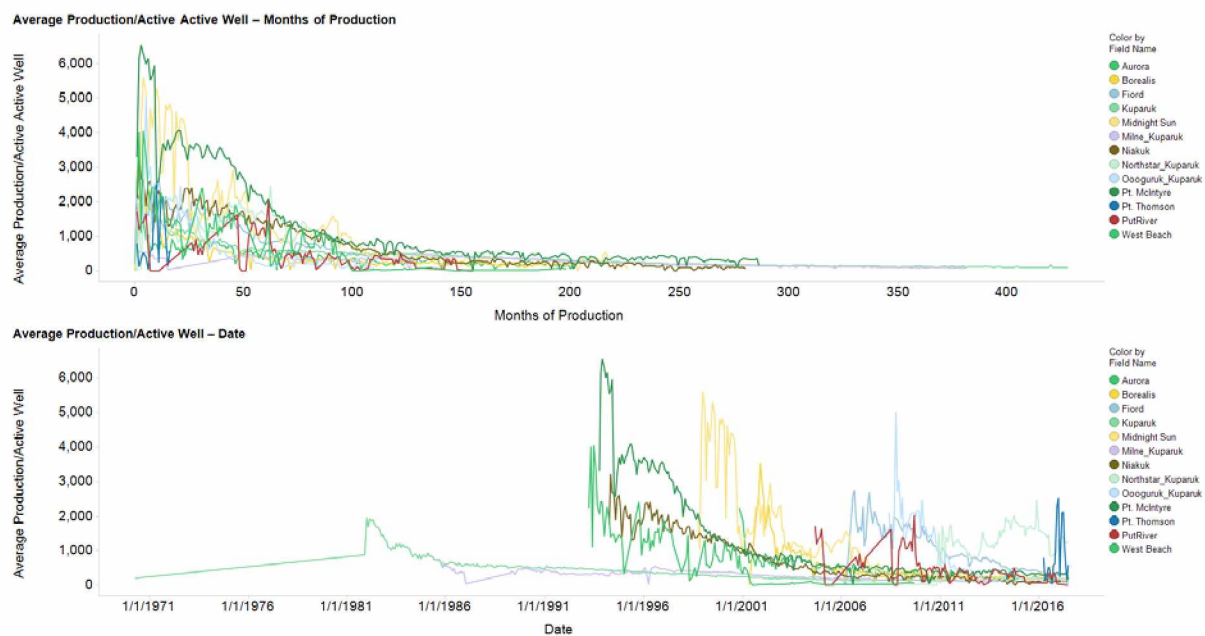


FIGURE 14: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) FIELDS WITH KUPARUK LIKE FORMATION

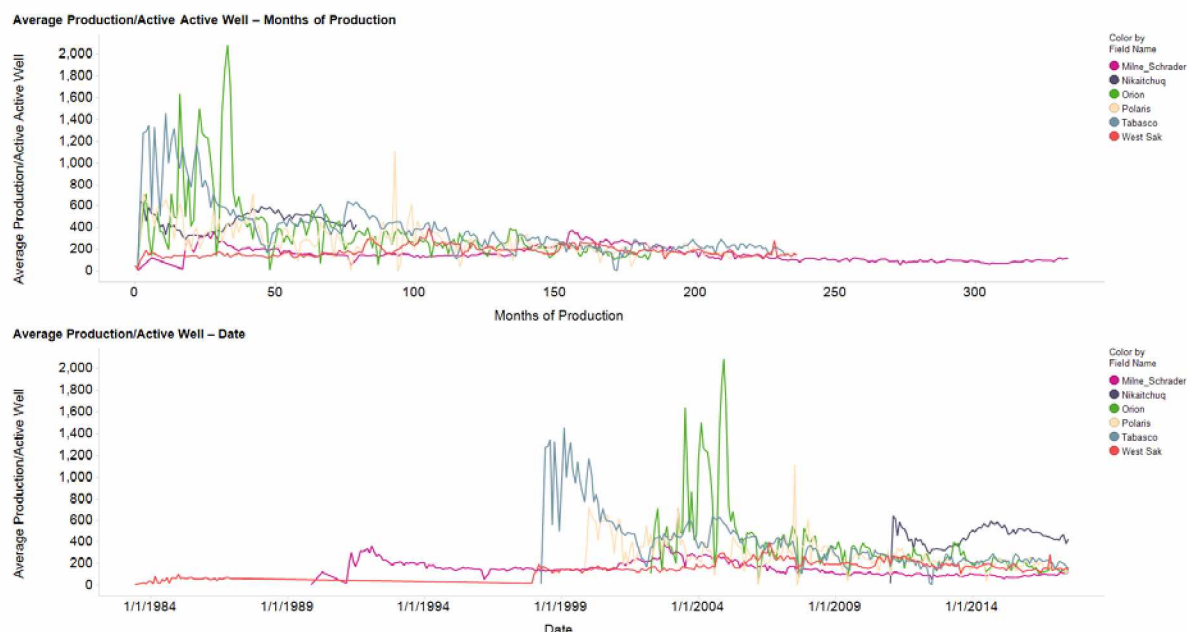


FIGURE 15: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) FIELDS WITH SCHRADER BLUFF LIKE FORMATION

Although there is a lot of variation in the fields across the North Slope, a series of trends can be made to predict reservoir performance and deliverability. This study generated a number of charts that can be seen in Figure 16 through Figure 30. Figure 16 depicts the permeability times the net formation height divided by the viscosity, a ratio central to Darcy's law that can be used to predict the cumulative oil per well a field will deliver. This chart, which is one of the key outcomes of this study, is critical in comparing the productivity of different targets. Though there is some spread in the achievable values based on reservoir rock and fluid properties alone, as it uses field average properties and public data, recovery per well for an exploration target should be benchmarked against this. For example, if a discovery has properties where the net thickness times the permeability divided by the viscosity is around 1,000 md-ft/cp, then the field will likely produce around a million barrels per well, with a downside of 500,000 barrels, and an upside of 2 million barrels. For a field to produce an average of four million barrels per well, it needs reservoir properties around 40,000 md-ft/cp. Improvements in well technology and enhanced oil recovery may help well productivity overall, however, many fields in this plot already employ those technologies. Figure 17 demonstrates the need for considering offline wells when using analog field profiles when creating type curves. The Y axis is the cumulative oil of the active producer average rate profile with time as seen in Figure 8 to Figure 15, while the X axis is the cumulative oil divided by the lifetime wells and adjusted by the Producer:Injector ratio to estimate the total number of producers. This plot demonstrates that if the active producer average rate profile is used as an analog, instead of including poor wells that get shut in early wells with poor on-time, the analog profile will estimate a rate around twice as high as one that considers all wells. This is important, as the bias of engineers tends to take the success cases and assume those are the most likely case of the future development, rather than truly represent a development with a combination of successes and failures. Prudhoe Bay is an outlier in this chart as it has a very active production optimization program with cycle producers and seasonal production capacity fluctuations. Figure 18 through Figure 30 can be used to estimate reservoir properties prior to discovery of a field, or for estimating reservoir properties of announced discoveries of which minimal information may be publicly available. It is important to consider the formation, location, and depth of Northstar and Minke (also known as Endicott Sag-Ivishak) which appear as outliers in some reservoir properties.

KH/μ vs. Cum Oil/Lifetime Wells

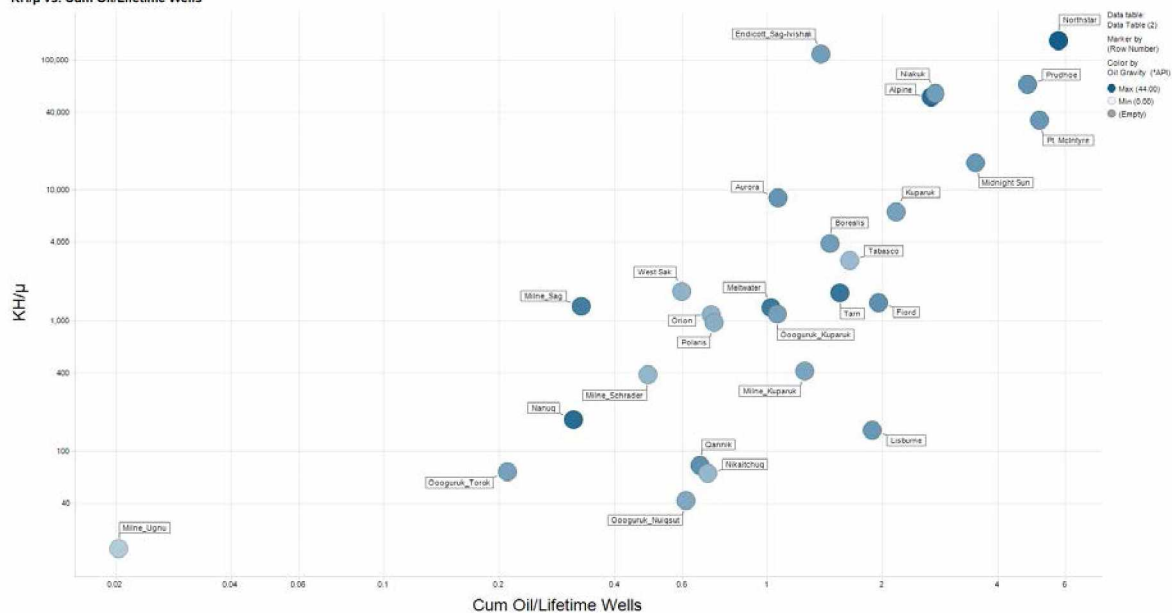


FIGURE 16: KH/M VS. CUM OIL/LIFETIME WELLS DRILLED BY FIELD

Cum Oil/Active Producer Profile vs. P:I Adjusted Cum Oil/Producer

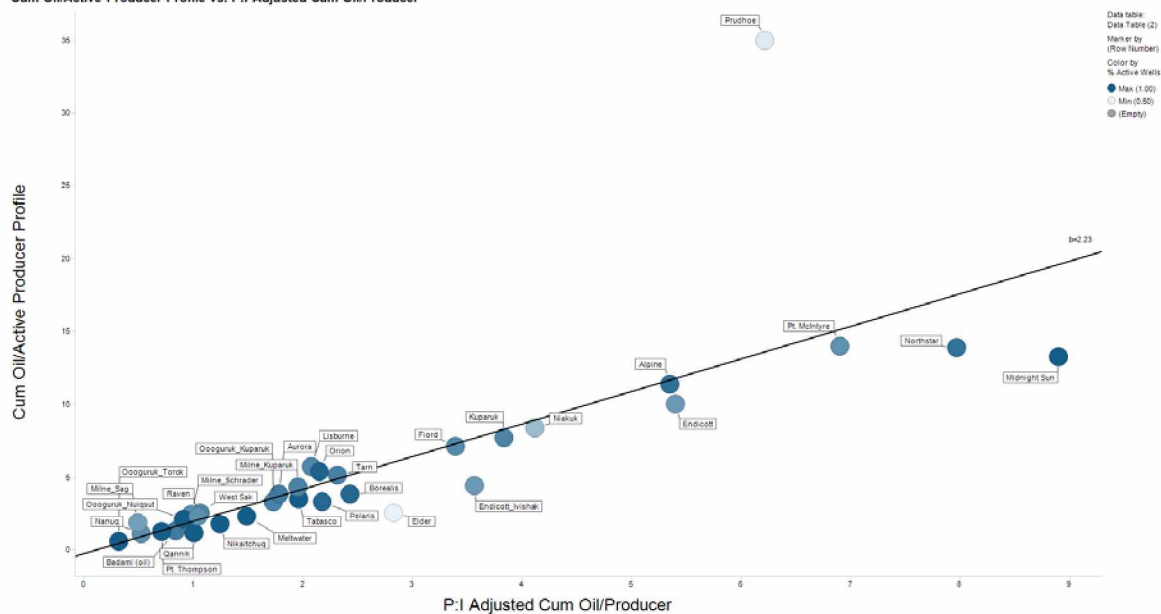


FIGURE 17: CUM OIL/ACTIVE PRODUCER PROFILE VS. PRODUCER:INJECTOR RATIO ADJUSTED CUM OIL/PRODUCER BY FIELD

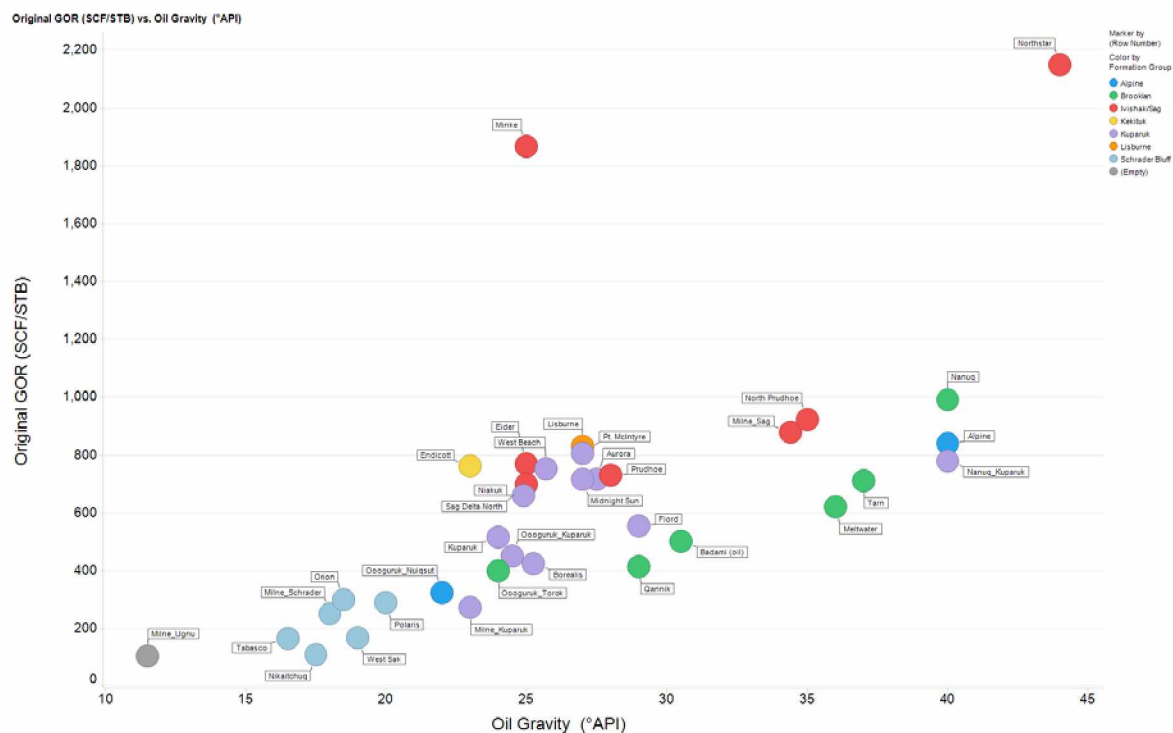


FIGURE 18: ORIGINAL GAS OIL RATIO VS. OIL GRAVITY

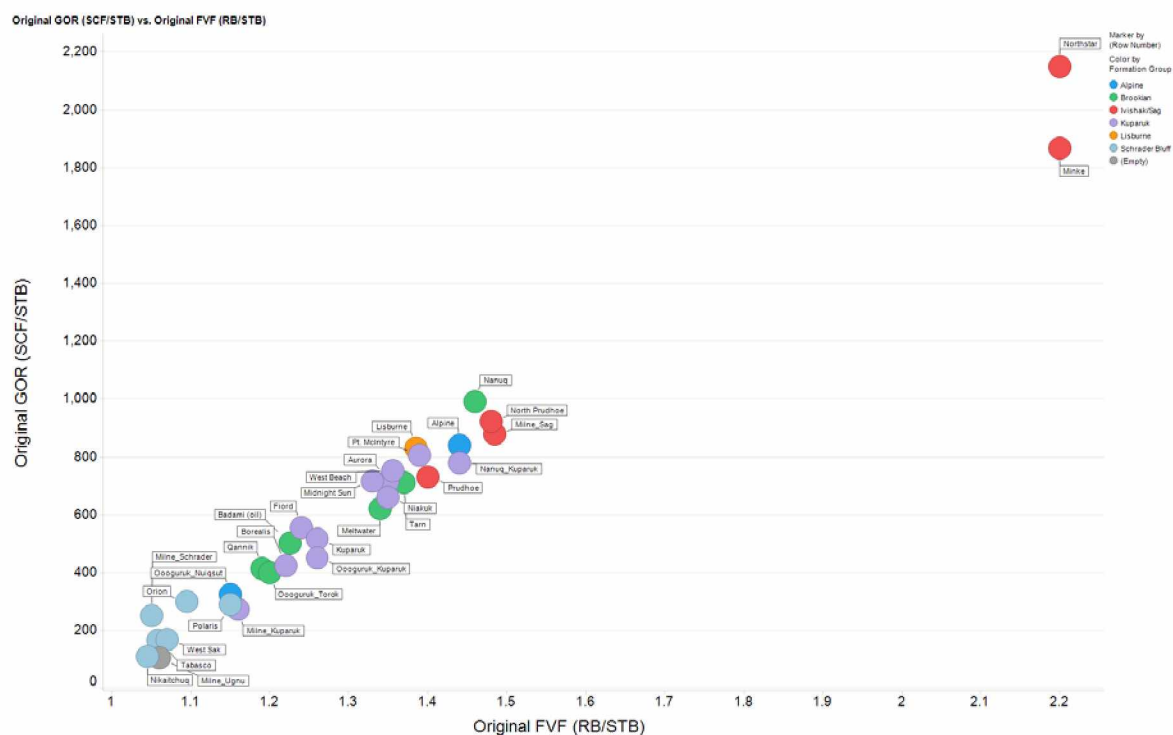


FIGURE 19: ORIGINAL GAS OIL RATIO VS. ORIGINAL FORMATION VOLUME FACTOR



FIGURE 20: REFERENCE DATUM VS. ORIGINAL GAS OIL RATIO

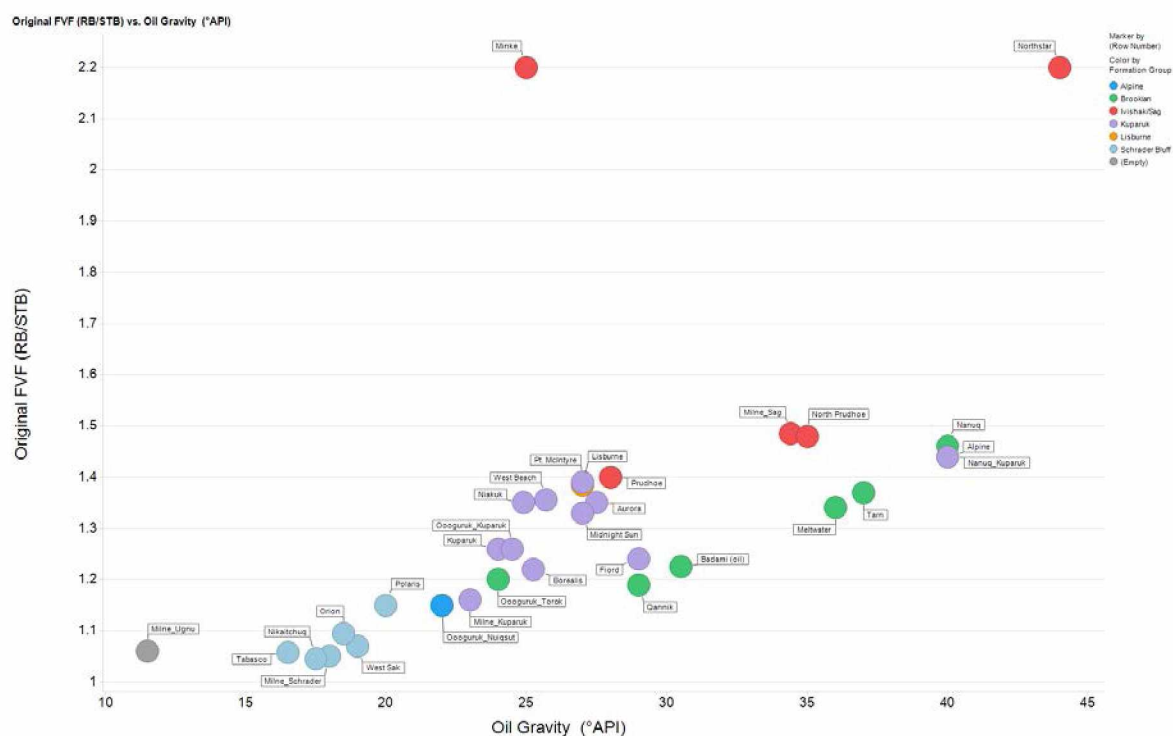


FIGURE 21: ORIGINAL FORMATION VOLUME FACTOR VS. OIL GRAVITY



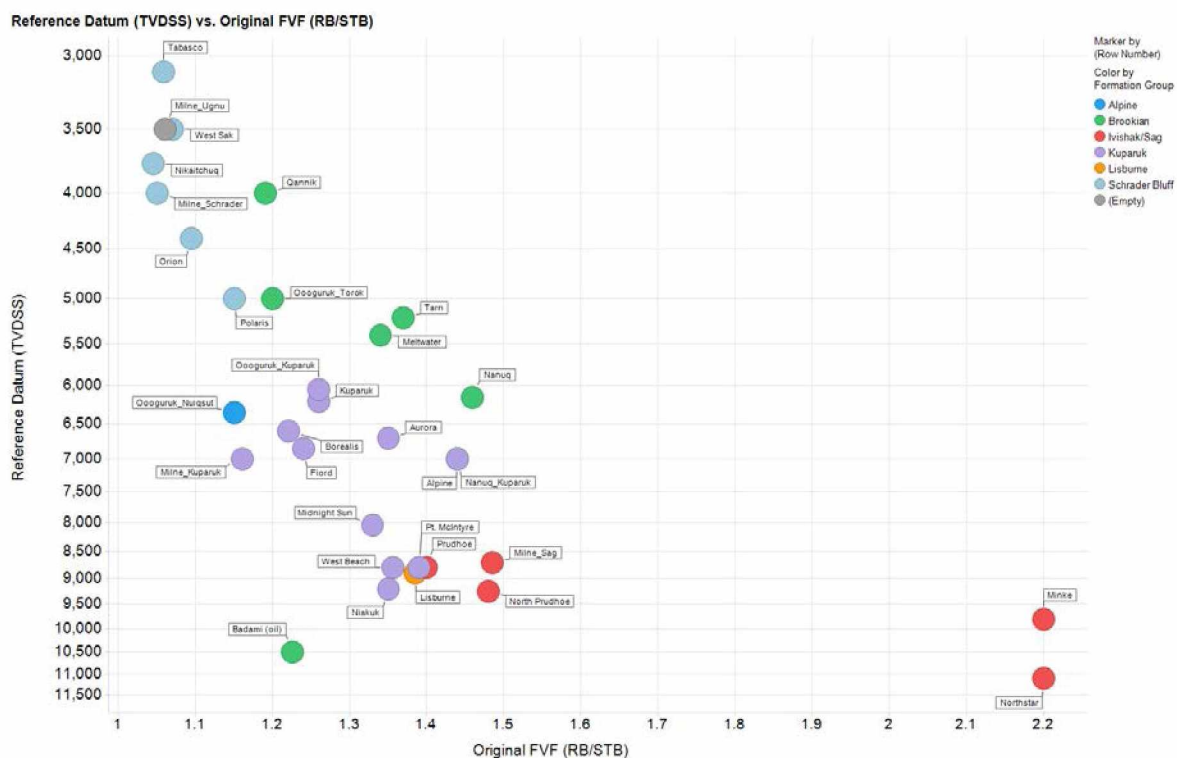


FIGURE 22: REFERENCE DATUM VS. ORIGINAL FORMATION VOLUME FACTOR

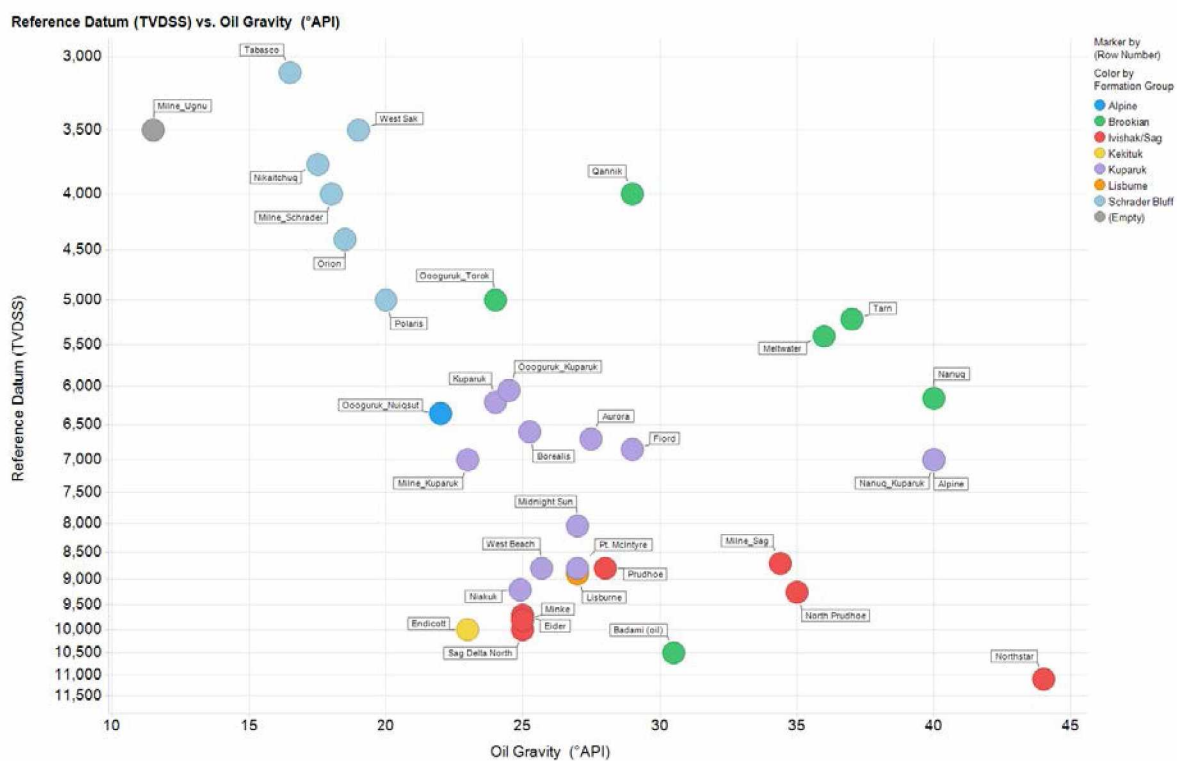


FIGURE 23: REFERENCE DATUM VS. OIL GRAVITY

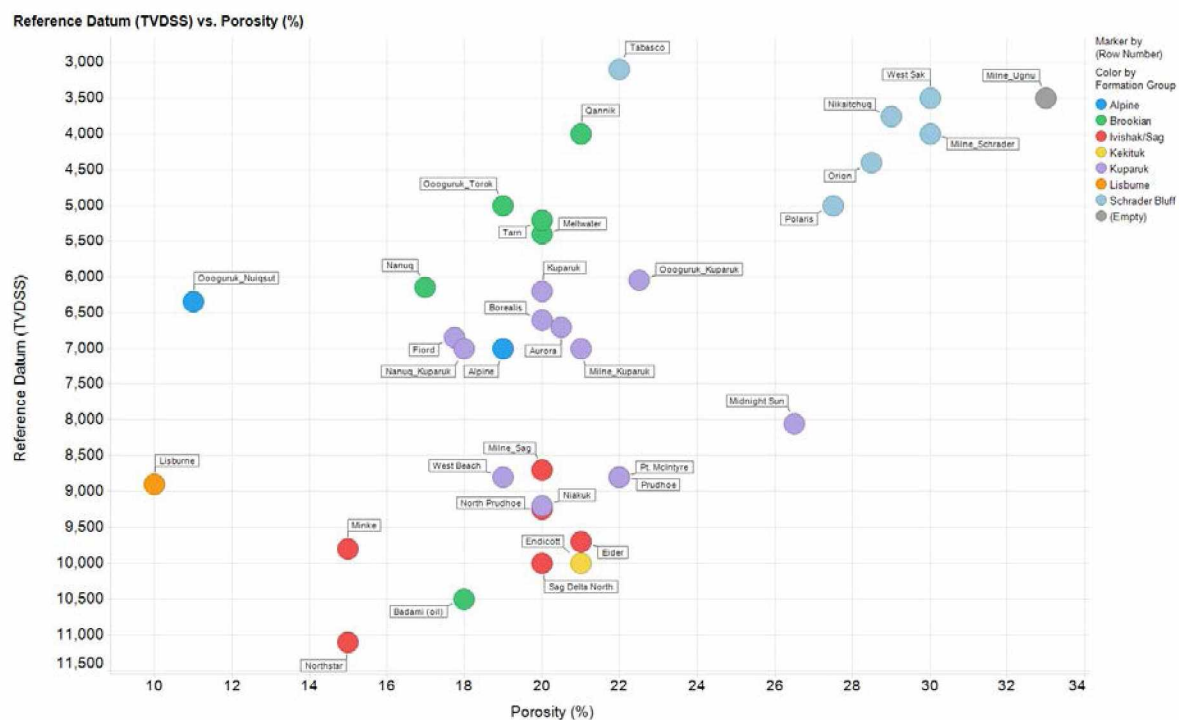


FIGURE 24: REFERENCE DATUM V. POROSITY

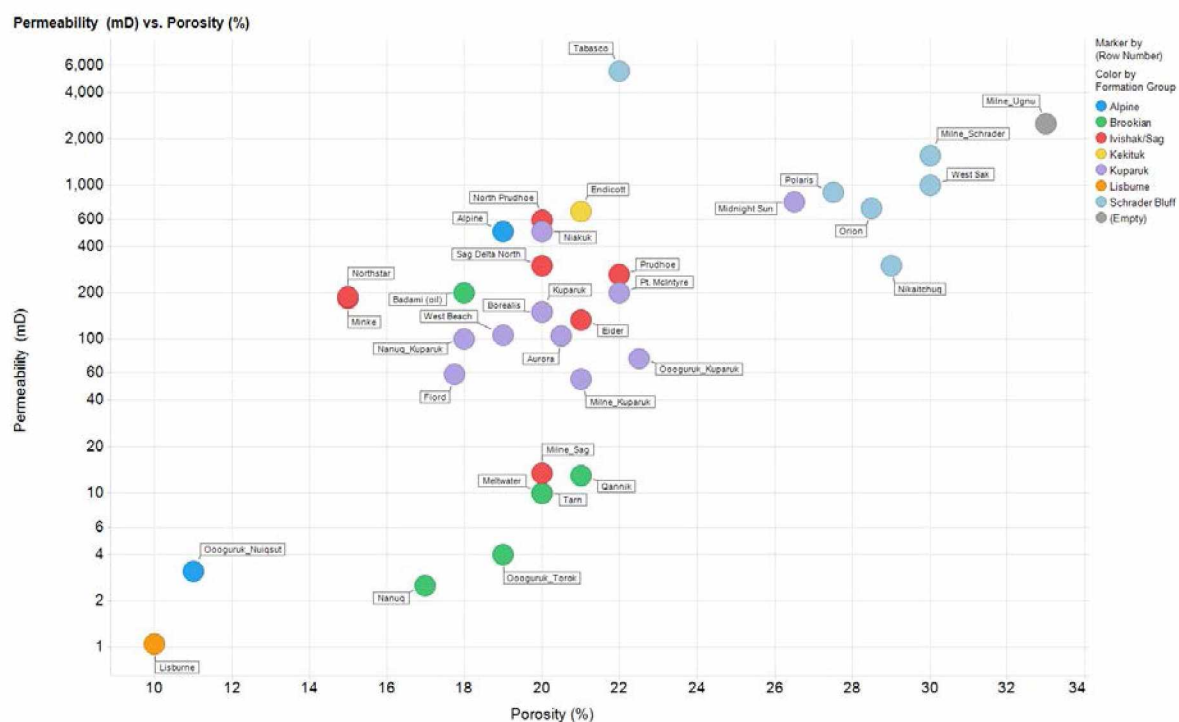


FIGURE 25: PERMEABILITY VS. POROSITY



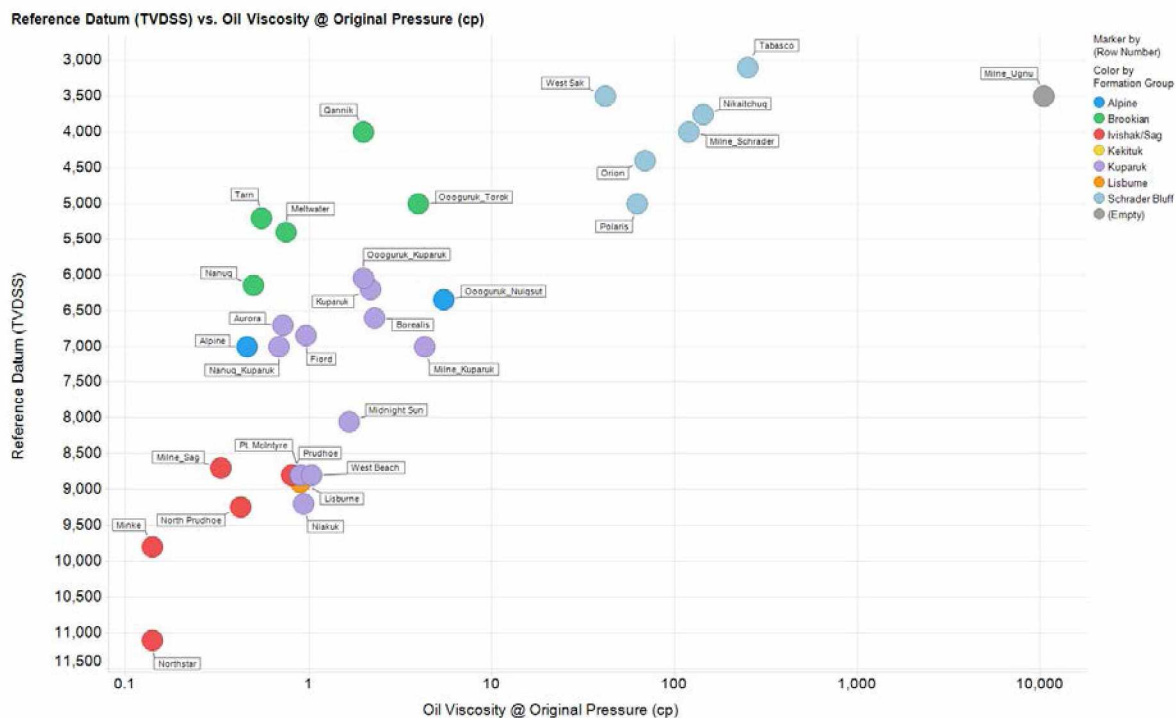


FIGURE 26: REFERENCE DATUM VS. OIL VISCOSITY

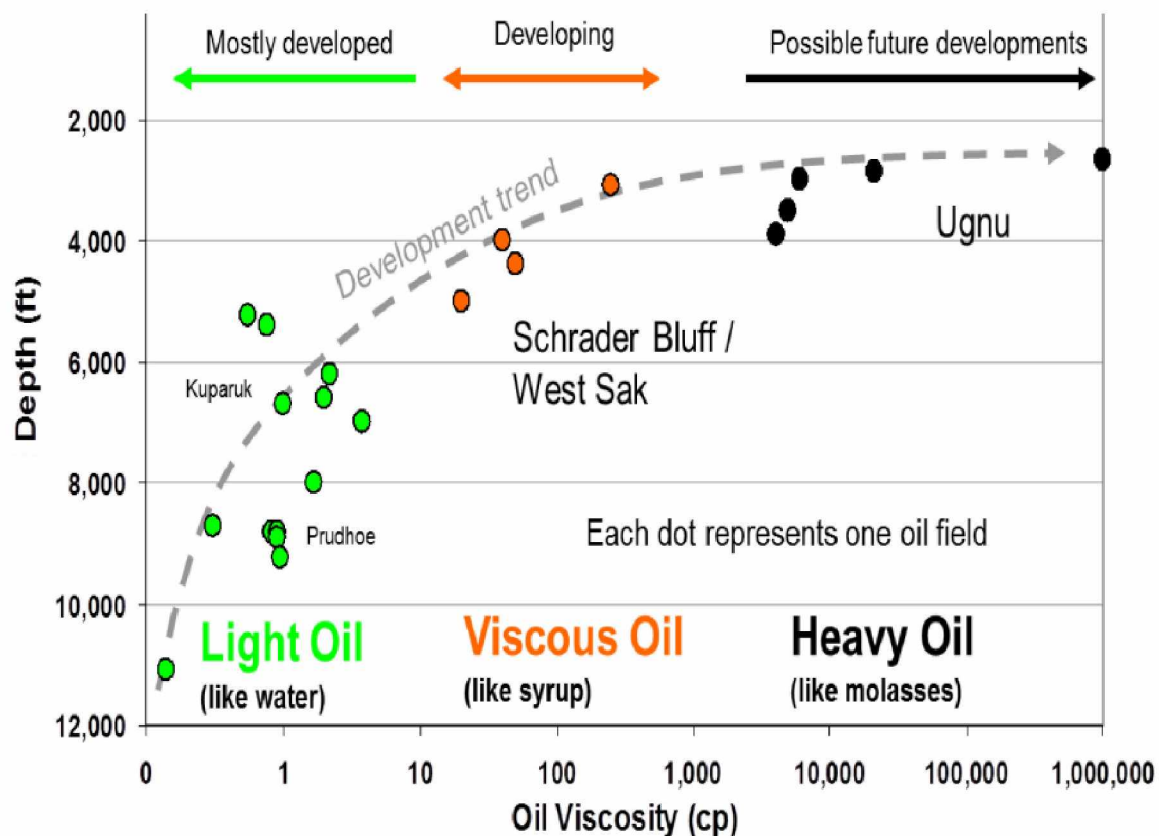


FIGURE 27: DEPTH VS. OIL VISCOSITY (PASKVAN, ET AL., 2016)

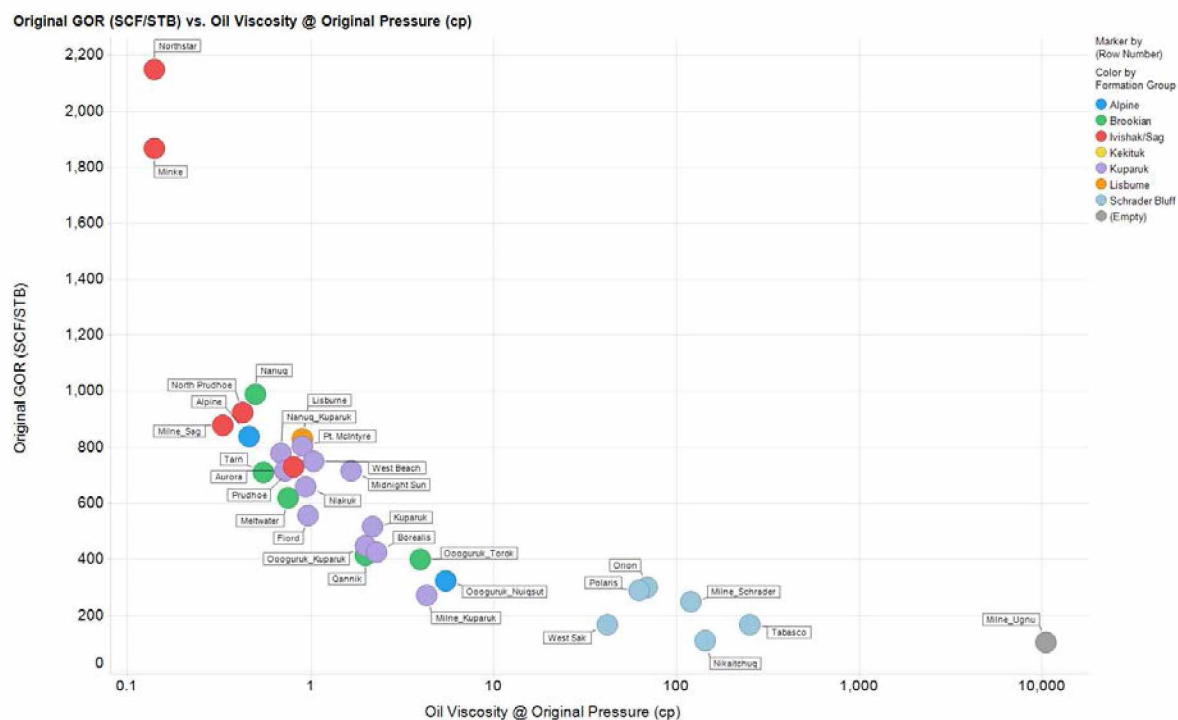


FIGURE 28: GOR VS. OIL VISCOSITY

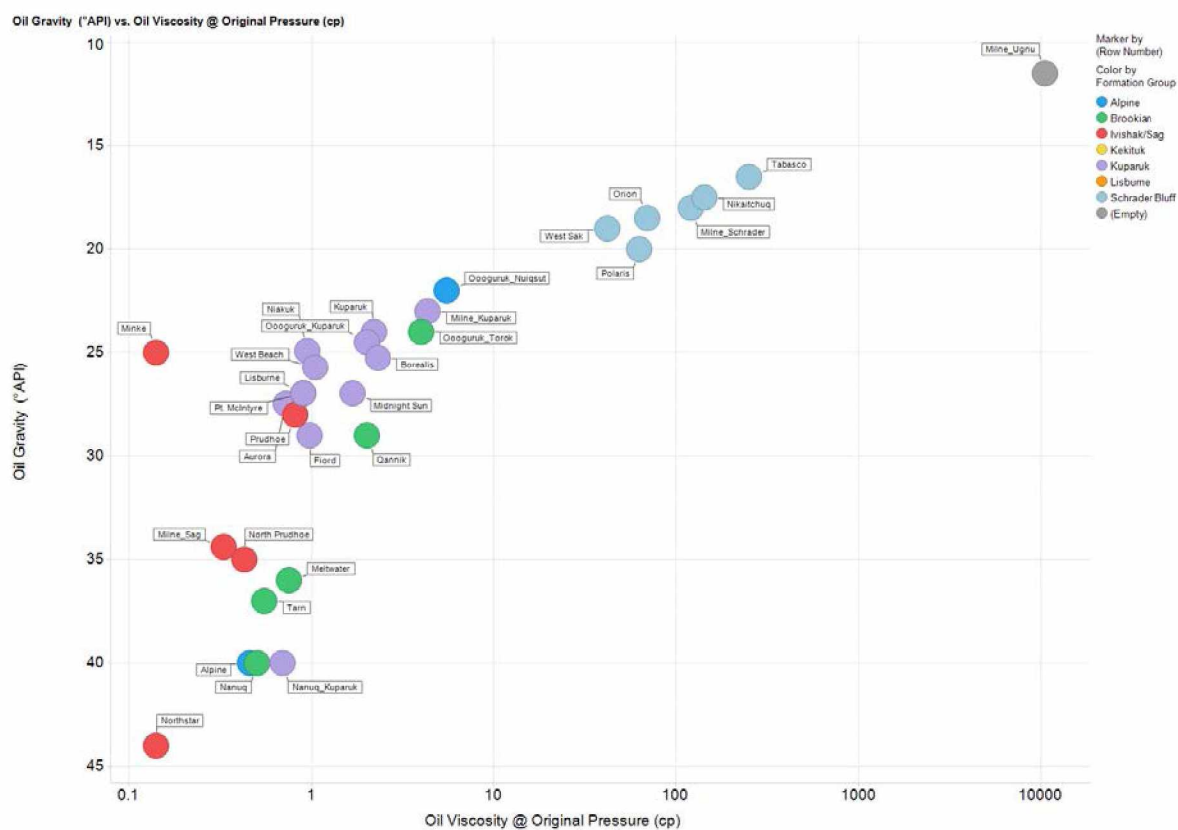


FIGURE 29: OIL GRAVITY VS. VISCOSITY

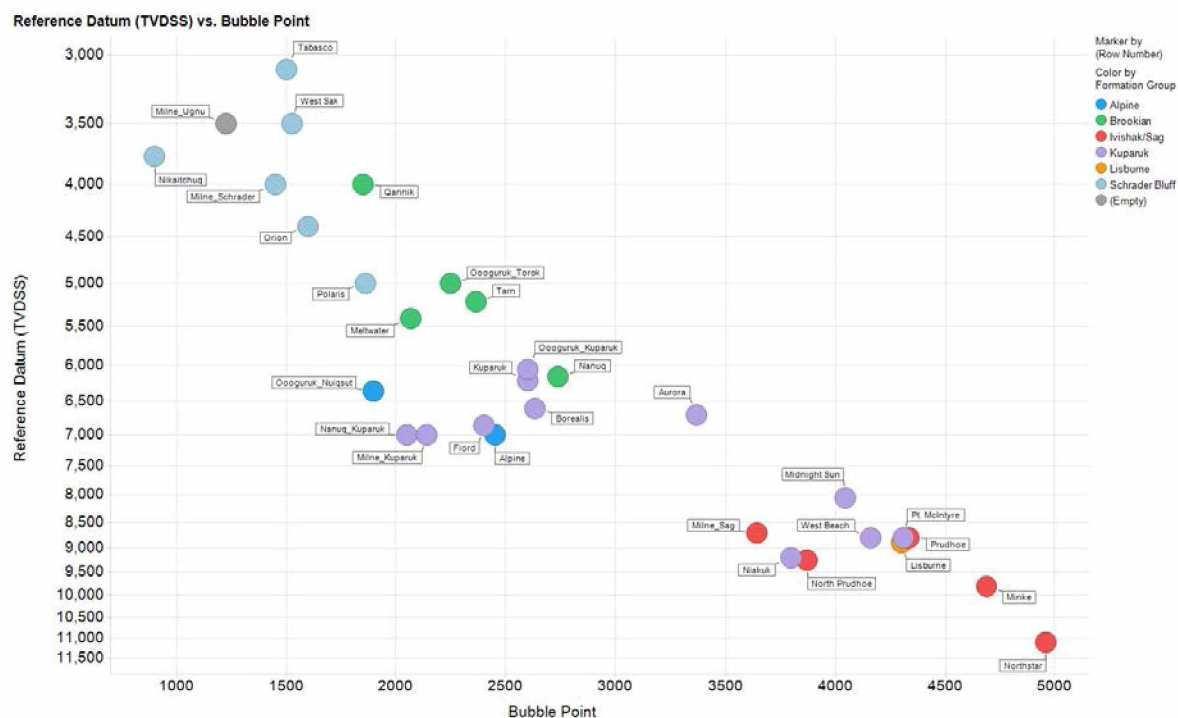


FIGURE 30: REFERENCE DATUM VS. BUBBLE POINT

## 6. NORTH SLOPE UNITS

### 7. BADAMI

The Badami field is located about 35 miles to the east of Prudhoe Bay. The field produces from a Brookian turbidite sand, was discovered in 1990, and came online in 1998, about 18 months after project sanction. Badami has a dedicated facility capable of producing oil rates of 35,000 bopd, water rates 30,000 bwpd, and handling 28 mmcf of gas injection and 10 mmcf of lift gas. The original development plan included 22 producers, 13 WAG injectors, 2 source water wells, and a disposal well. (Repp & Ennis, 1999). As seen in Figure 34, the field peaked above 7,000 bopd with 8 wells online, but fell quickly. Soon after development it became apparent that the field was much more compartmentalized than previously expected, which allowed for high initial rates, but hampered long term productivity. The field is largely considered a development failure, and is a good example about the geologic complexity and the impacts on development. It is unclear in public documentation if additional appraisal before sanction would have predicted the level of compartmentalization. It is documented that the project was fast tracked and reservoir definition activities were done in parallel with facilities engineering (Repp & Ennis, 1999).

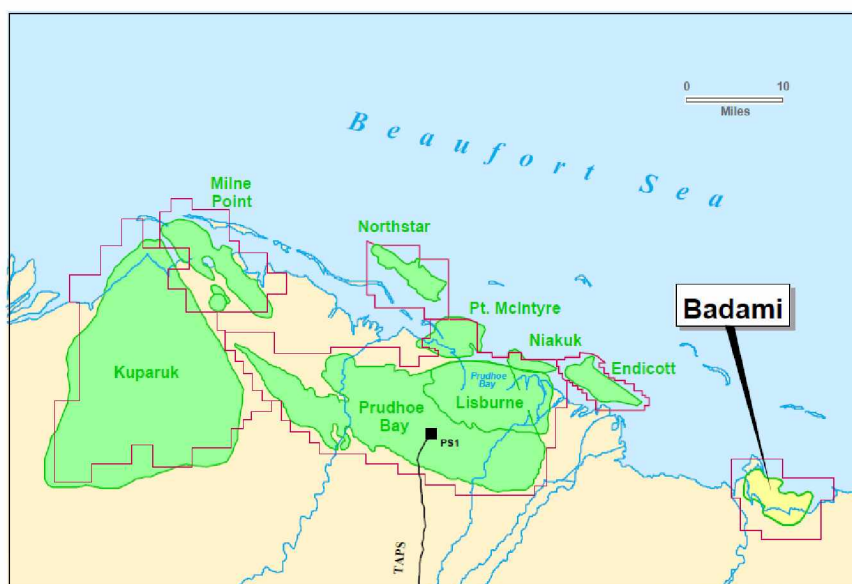


FIGURE 31: BADAMI LOCATION MAP (REPP & ENNIS, 1999)

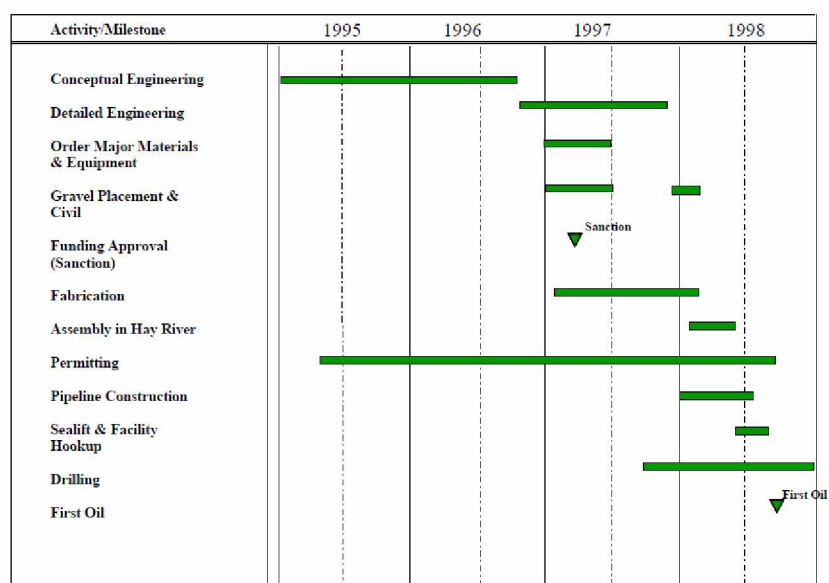


FIGURE 32: BADAMI PROJECT DEVELOPMENT GANTT CHART (REPP & ENNIS, 1999)

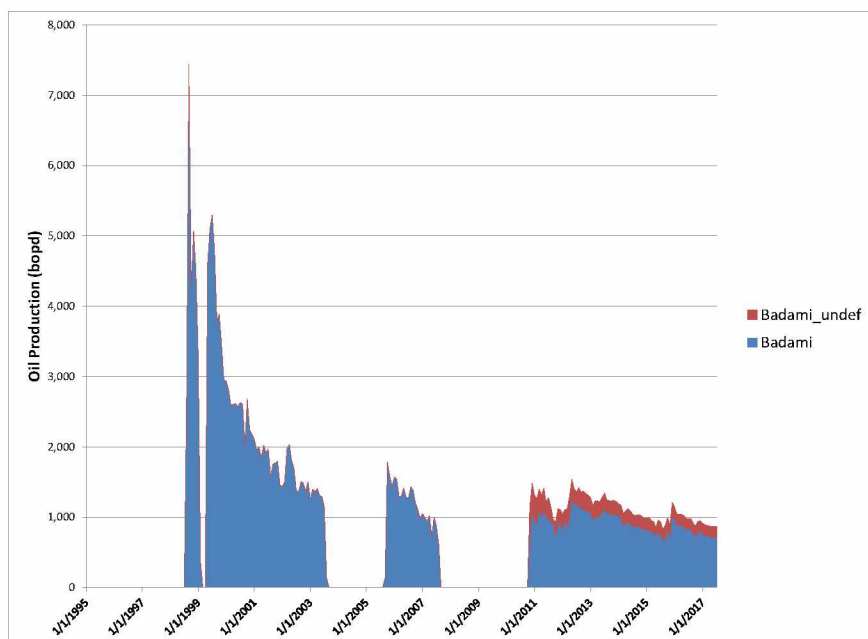


FIGURE 33: BADAMI UNIT PRODUCTION

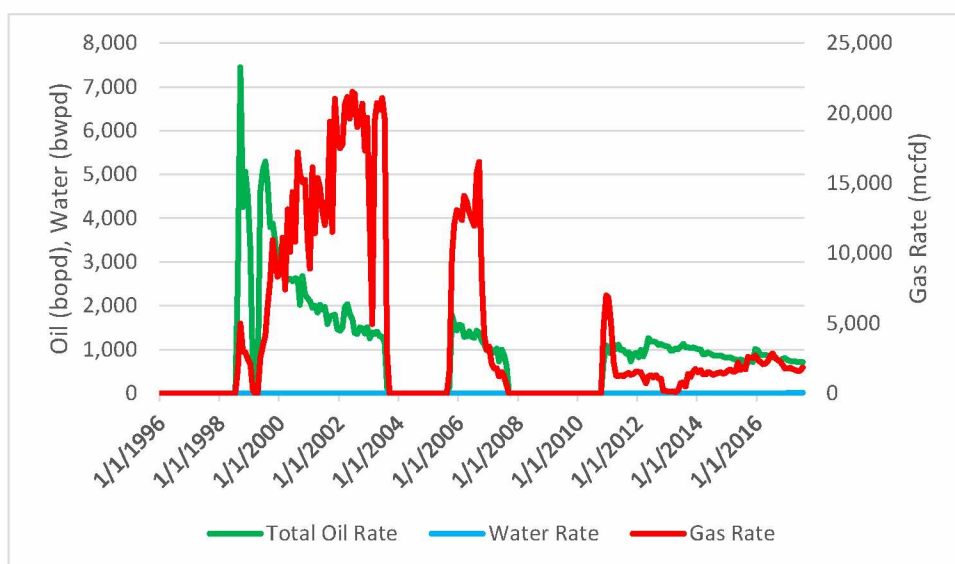


FIGURE 34: BADAMI FIELD PRODUCTION

## 8. COLVILLE RIVER

The Colville River Unit located about 30 miles west of Kuparuk, is operated by ConocoPhillips and comprises of the Alpine, Nanuq, Qannik, and Fiord fields. These fields all produce to the Alpine facility which is capable of handling 140,000 bopd, 180 mmcf/d of gas, and 100,000 bwpd (Kaltenbach, et al., 2004). With the recent drilling at CD5, the unit is producing 60,000 bopd, and the neighboring Greater Mooses Tooth Unit developments GMT1 and GMT2 are planned to produce to the Alpine facility. The Alpine unit is produces from the Jurassic Alpine Nechelik sands (Alpine, Fiord) with its satellite fields producing from Kuparuk (Fiord, Nanuq) and Brookian (Qannik, Nanuq) sands.

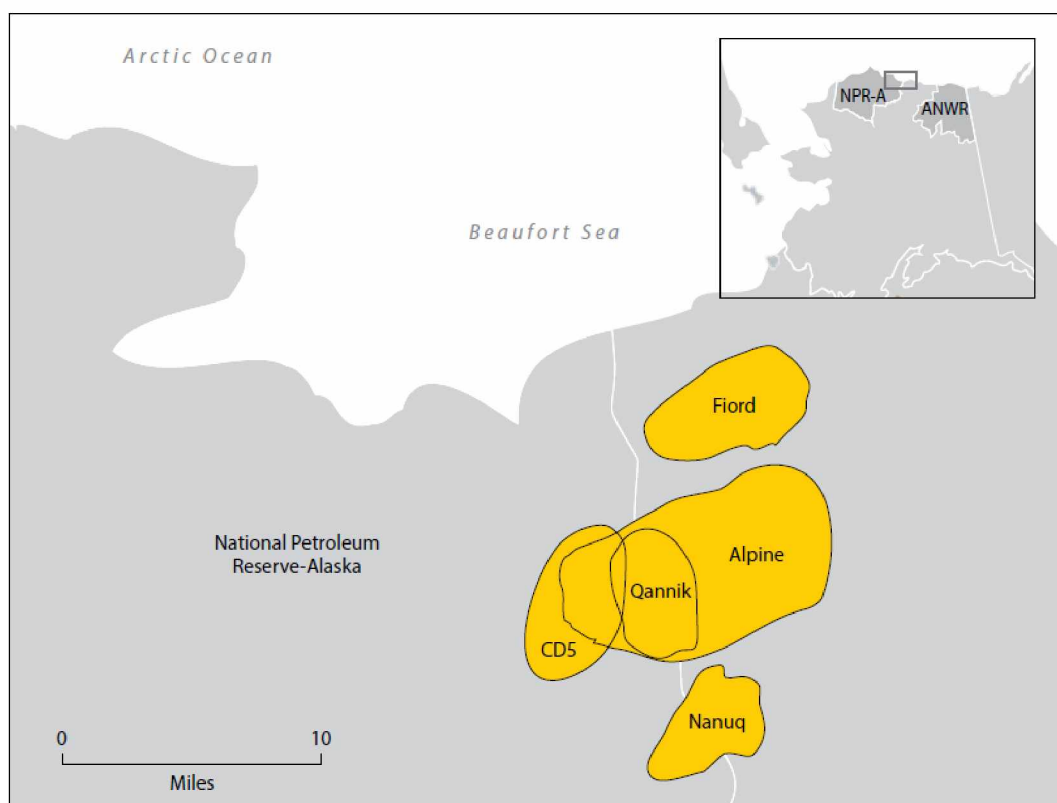


FIGURE 35: COLVILLE RIVER UNIT MAP (CONOCOPHILLIPS, 2017)

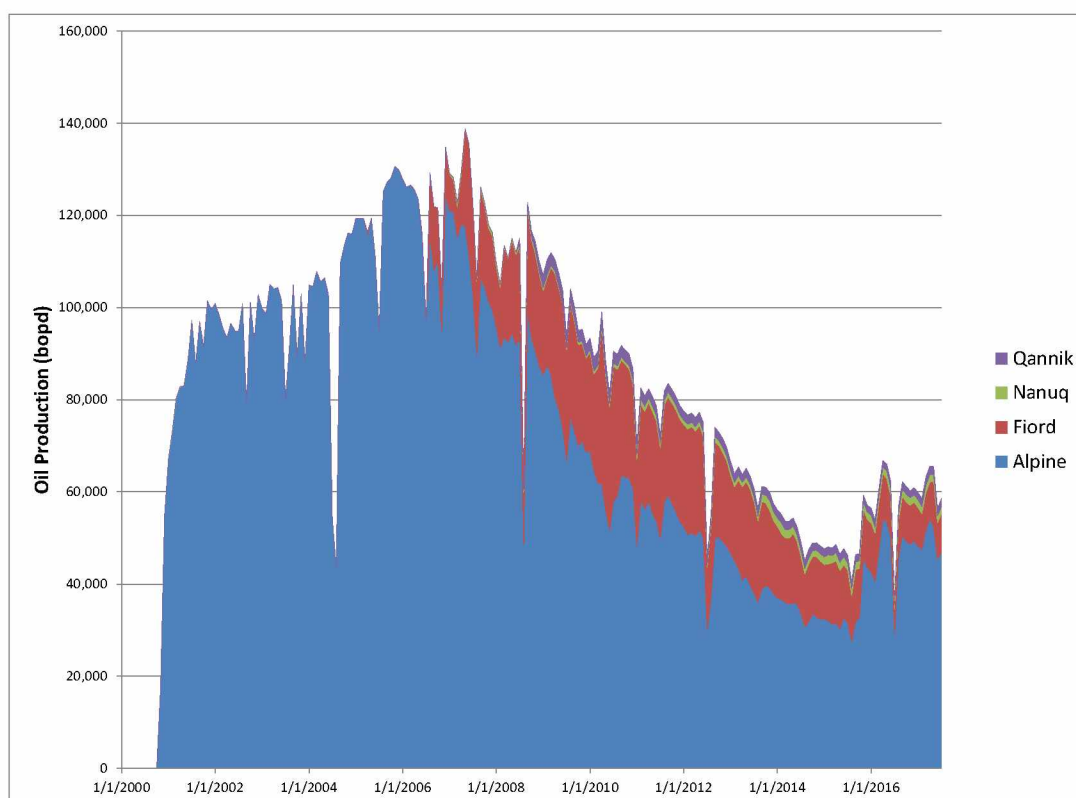


FIGURE 36: COLVILLE RIVER PRODUCTION

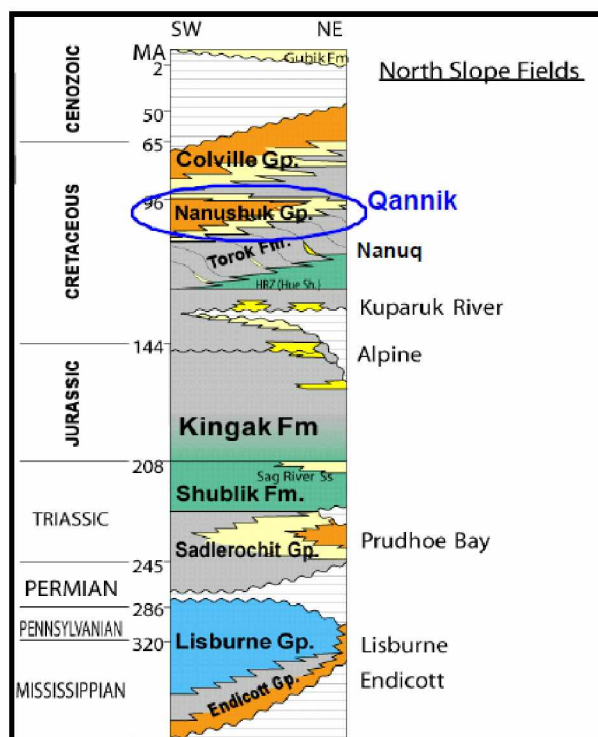


FIGURE 37: COLVILLE RIVER UNIT STRATIGRAPHIC COLUMN (ALVORD, ET AL., 2009)

## 8.1. ALPINE

The Alpine field produces from the Jurassic aged Alpine sands. Field development utilizes a 1:1 Producer:Injector ratio using both fractured and non-fractured horizontal producers and horizontal injectors creating a line drive pattern for the water alternating miscible gas (MWAG) flood. This has proven highly effective, with over 420 million barrels of oil produced to date after 17 years of production, making it the fifth largest producing field on the North Slope in terms of recovery. Recent drilling at CD5 has increased production at Alpine from approximately 20,000 bopd to 50,000 bopd as seen in Figure 40.

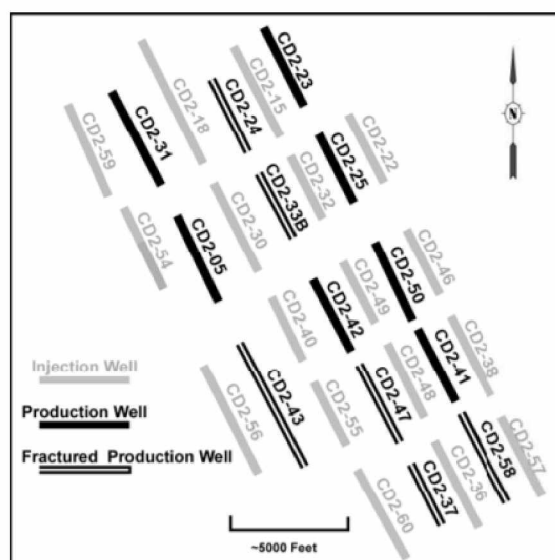


FIGURE 38: ALPINE FIELD MAP (SCHNEIDER, ULDRICH, HODGE, BARREE, & MARTIN)



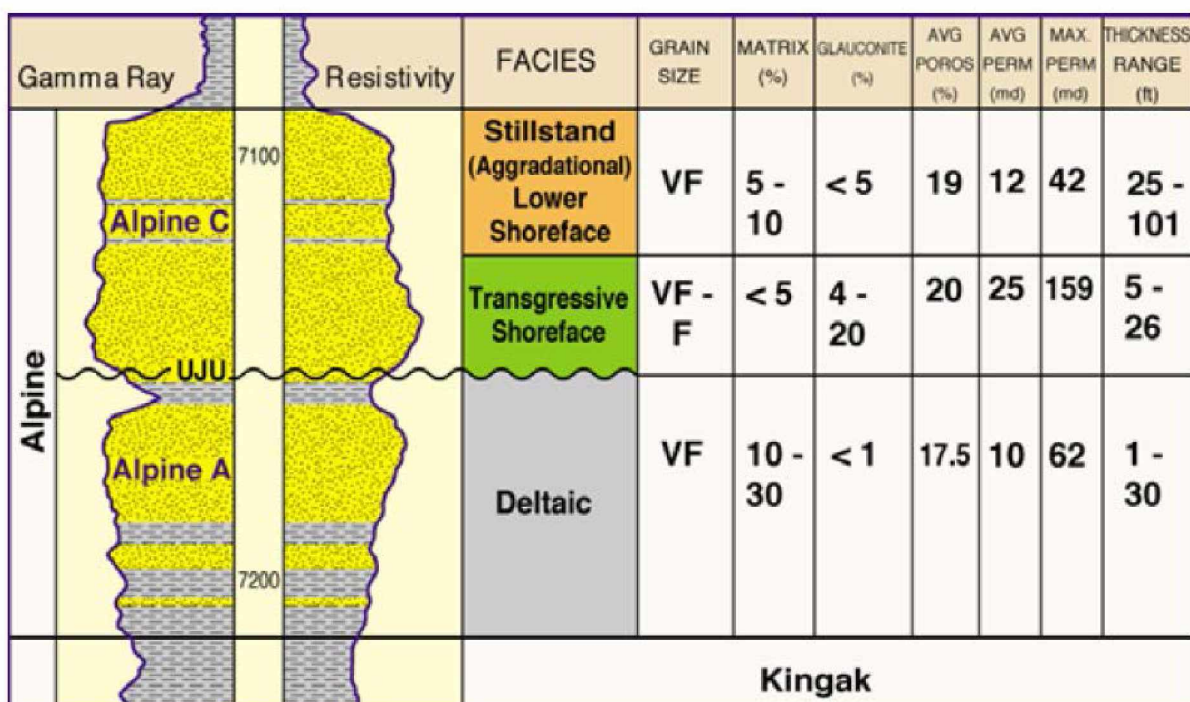


FIGURE 39: ALPINE COMPOSIT TYPE LOG (SCHNEIDER, ULDRICH, HODGE, BARREE, &amp; MARTIN)

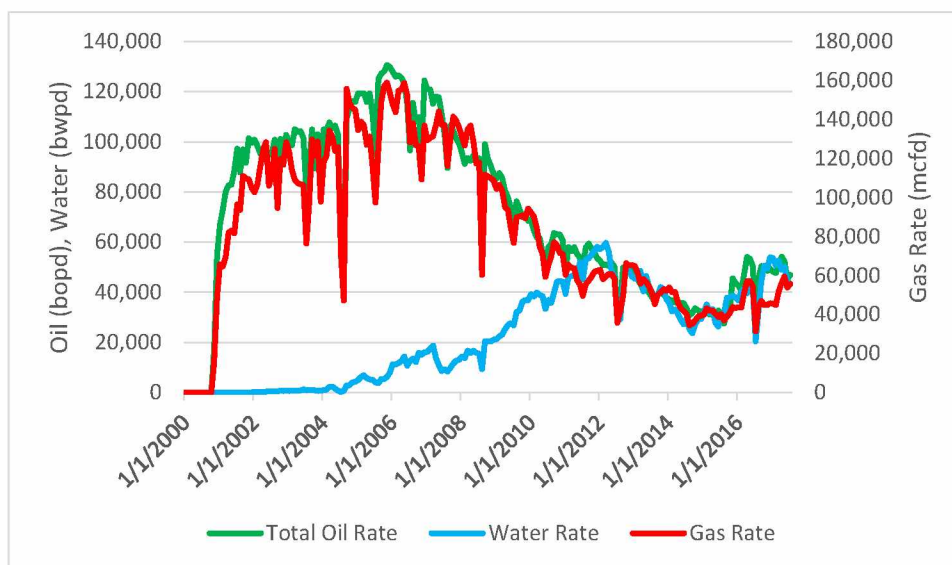


FIGURE 40: ALPINE FIELD PRODUCTION



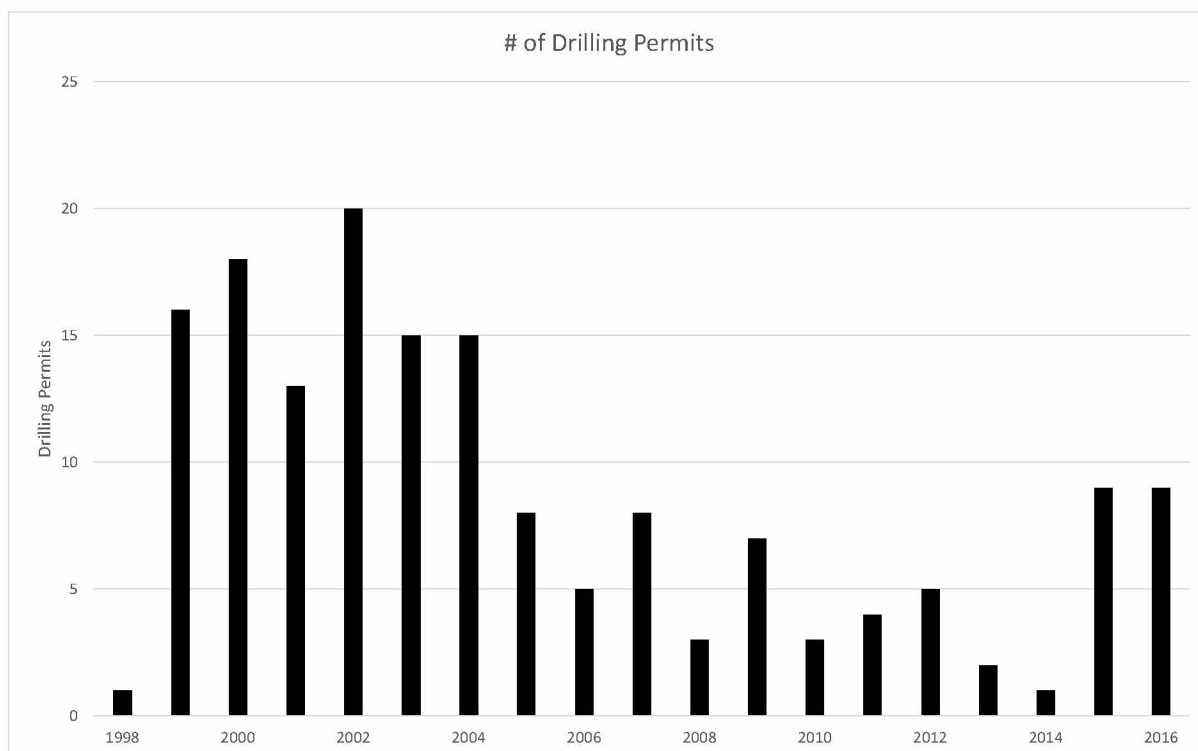


FIGURE 41: ALPINE DRILLING PERMITS BY YEAR



FIGURE 42: ALPINE PRODUCTION AND WELL COUNT

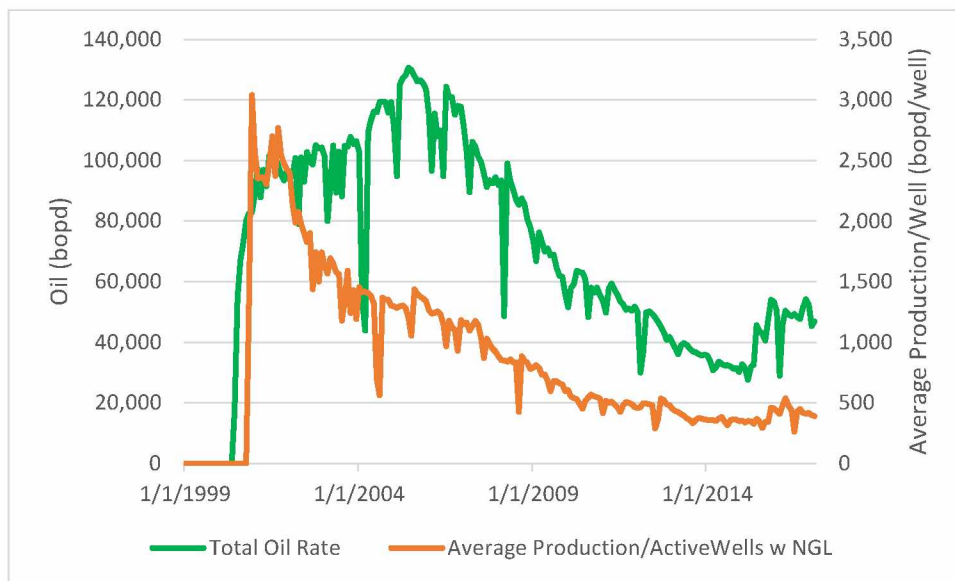


FIGURE 43: ALPINE FIELD PRODUCTION AND AVERAGE ACTIVE WELL PRODUCTION

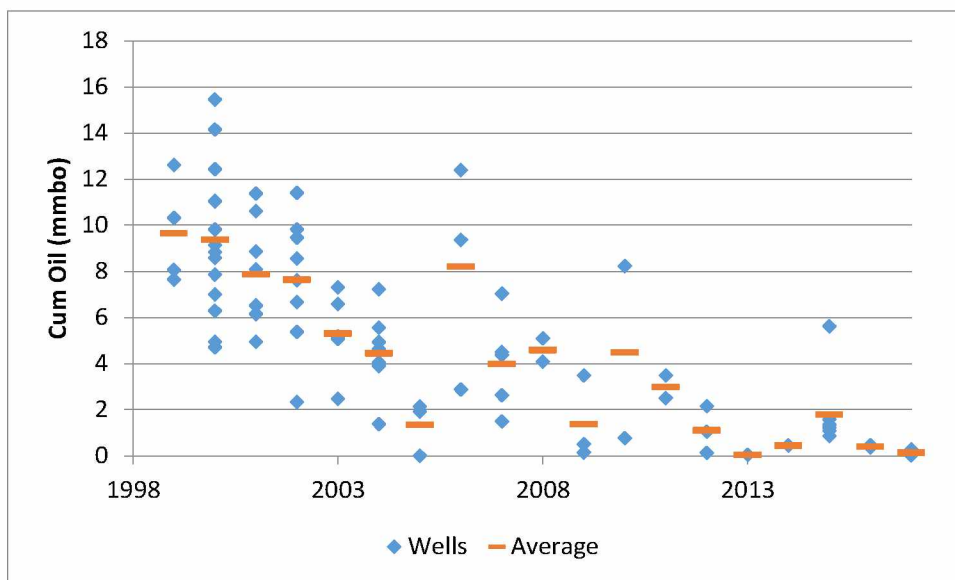


FIGURE 44: ALPINE WELL CUM OIL TO DATE BY PERMIT YEAR

## 8.2. FIORD

The Fiord Field produces from CD3 and comprises of a Kuparuk and Nechelik producing area. Production began in 2006 and peaked over 30,000 bopd. It is currently producing approximately 8,500 bopd, having cumulatively produced over 66 million barrels, making it the largest Alpine satellite field. There are 25-30 active wells in the pool.

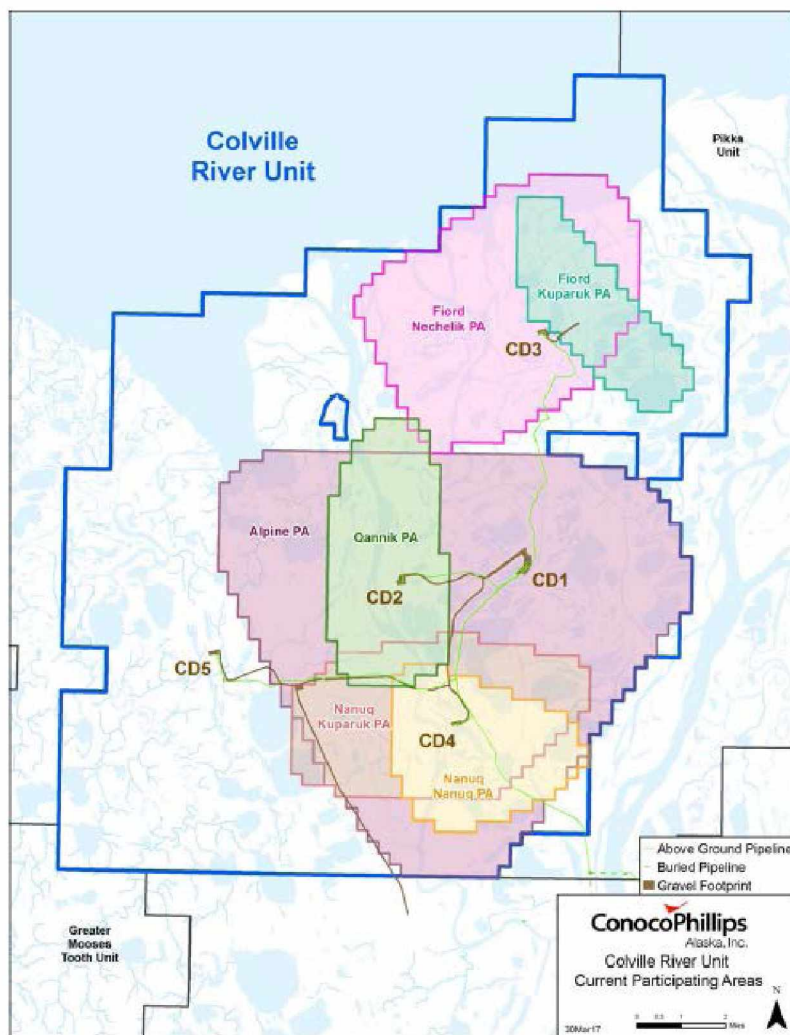


FIGURE 45: COLLVILLE RIVER UNIT PARTICIPATING AREAS MAP 2017 (CONOCOPHILLIPS, 2017)

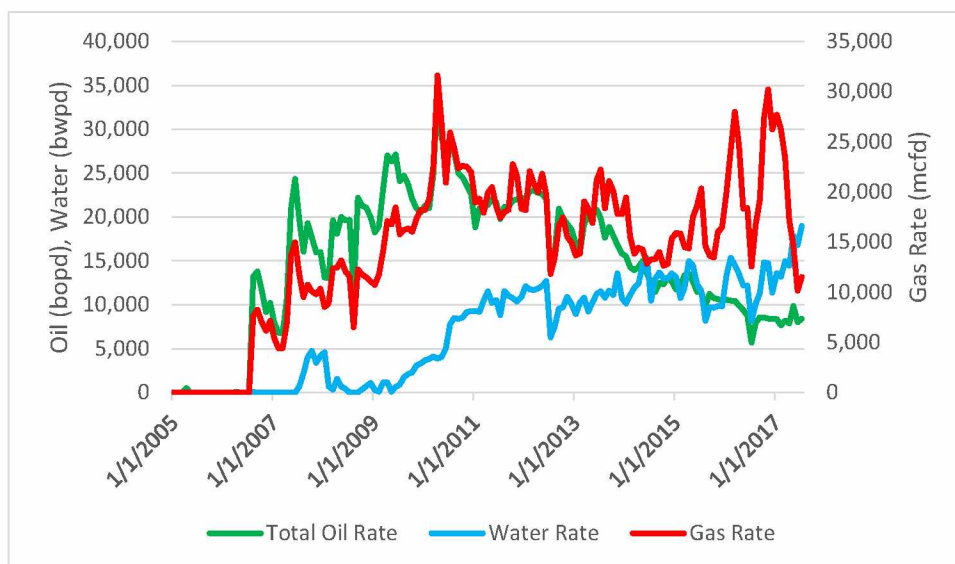


FIGURE 46: FIORD FIELD PRODUCTION

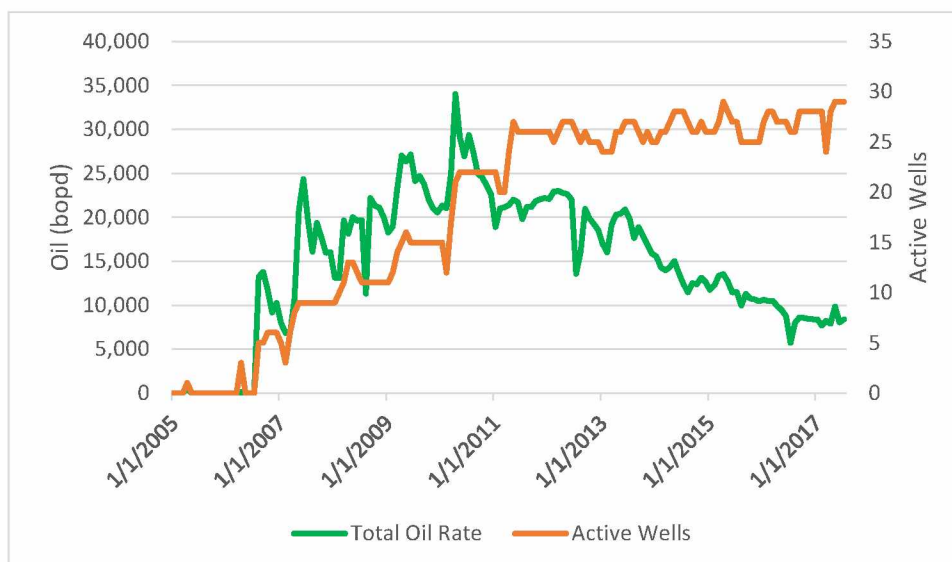


FIGURE 47: FIORD PRODUCTION AND WELL COUNT

### 8.3. NANUQ

The Nanuq field is developed at the CD4 drillsite and produces both in the Nanuq and Kuparuk sandstones. Production began in 2006 and the field is now up to 10 active wells producing a combined 1,500 bopd. It has made 3.7 million barrels to date, about 20% of the original expected low side of recoverable oil.

TABLE 2: NANUQ OIL IN PLACE AND RECOVERABLE VOLUMES (AOGCC, 2005)

Oil in place, MMSTB	84 – 169
Recoverable Oil, MMSTB	22 – 69
Gas in place, BSCF	40

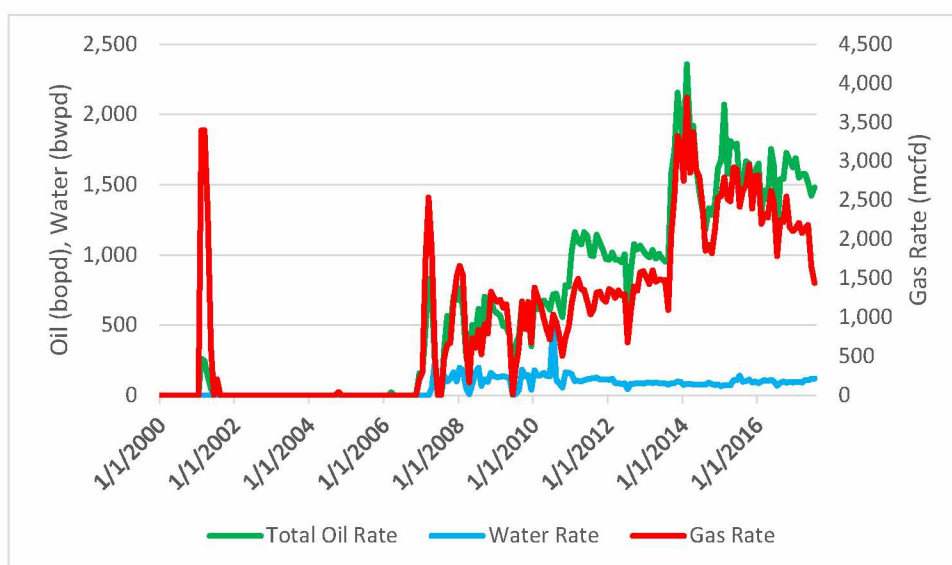


FIGURE 48: NANUQ FIELD PRODUCTION

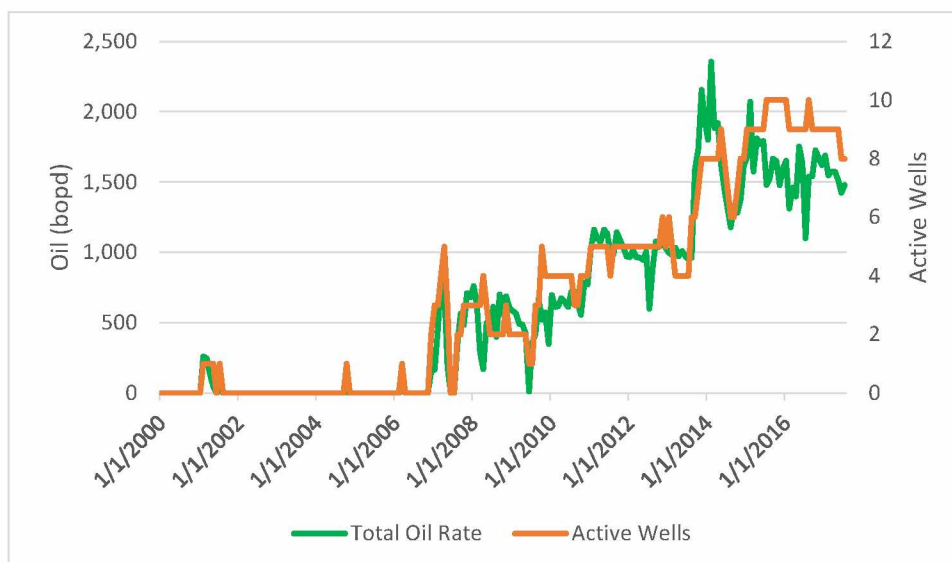


FIGURE 49: NANUQ PRODUCTION &amp; ACTIVE WELLS

#### 8.4. QANNIK

The Qannik field produces from CD2 from the Qannik formation. Production began in 2008 and peaked at 3,000 bopd. Currently the field produces 1,700 bopd with 9 active wells and has produced 6 million barrels of oil, about a third of the originally expected 17 million barrels development.

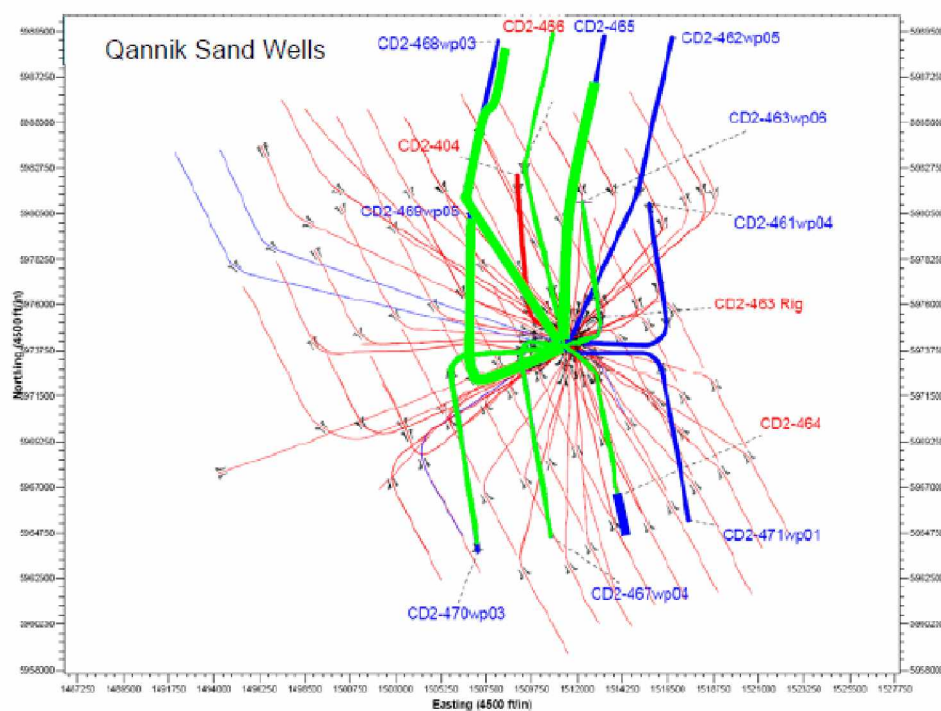


FIGURE 50: QANNIK WELL PATH SPIDER MAP (ALVORD, ET AL., 2009)



TABLE 3: QANNIK WELL DATA (ALVORD, ET AL., 2009)

Well Name	CD2-404	CD2-464	CD2-463	CD2-467	CD-470	CD2-466	CD2-465	CD2-469	CD2-468
Planned Mud Weight	9.9	9.9	9.5	9.5	9.5	9.5	9.6	9.6	9.6
Total Depth	11540	10776	10896	13836	15233	18286	13733	14297	17850
Total Length	5969	5724	5727	8427	7284	7494	4084	6891	7218
Planned TD	11533	13742	10904	14048	16716	18459	17212	14854	18614
Modeled ECD at TD	12.01	11.07	10.8	11.1	11.37	11.55	11.52	11.26	11.66
Modeled Pump Rate at TD	280	300	300	300	300	300	300	300	300
Actual ECD at TD	12.15	11.01	10.83	10.64	11.05	11.45	11.01	10.97	11.3
Actual Pump Rate at TD	278	267	297	275	285	290	300	275	272
Max Mud Weight	10	10.5	9.65	9.6	9.55	9.6	9.65	9.6	9.65
Max YP	15	11	6	8	7	6	5	5	5
Max 3/6 RPM	7/8	4/4	2/3	3/4	3/6	2/3	2/3	2/3	2/3
Total Losses	997	1019	114	513	508	760	65	1316	349
Footage Drilled in Fractured Zone	NA	870	160	0	707	160	230	340	450
Departure	9224	8159	8378	11430	13479	16772	12060	12459	16297
Departure/TVD Ratio	2.30	2.00	2.05	2.79	3.24	4.16	2.95	3.07	4.00
% Lateral in zone	64	90	86	80	70	99	96	84	96
% Net/Gross sand	84	30	72	59	68	52	80	58	60

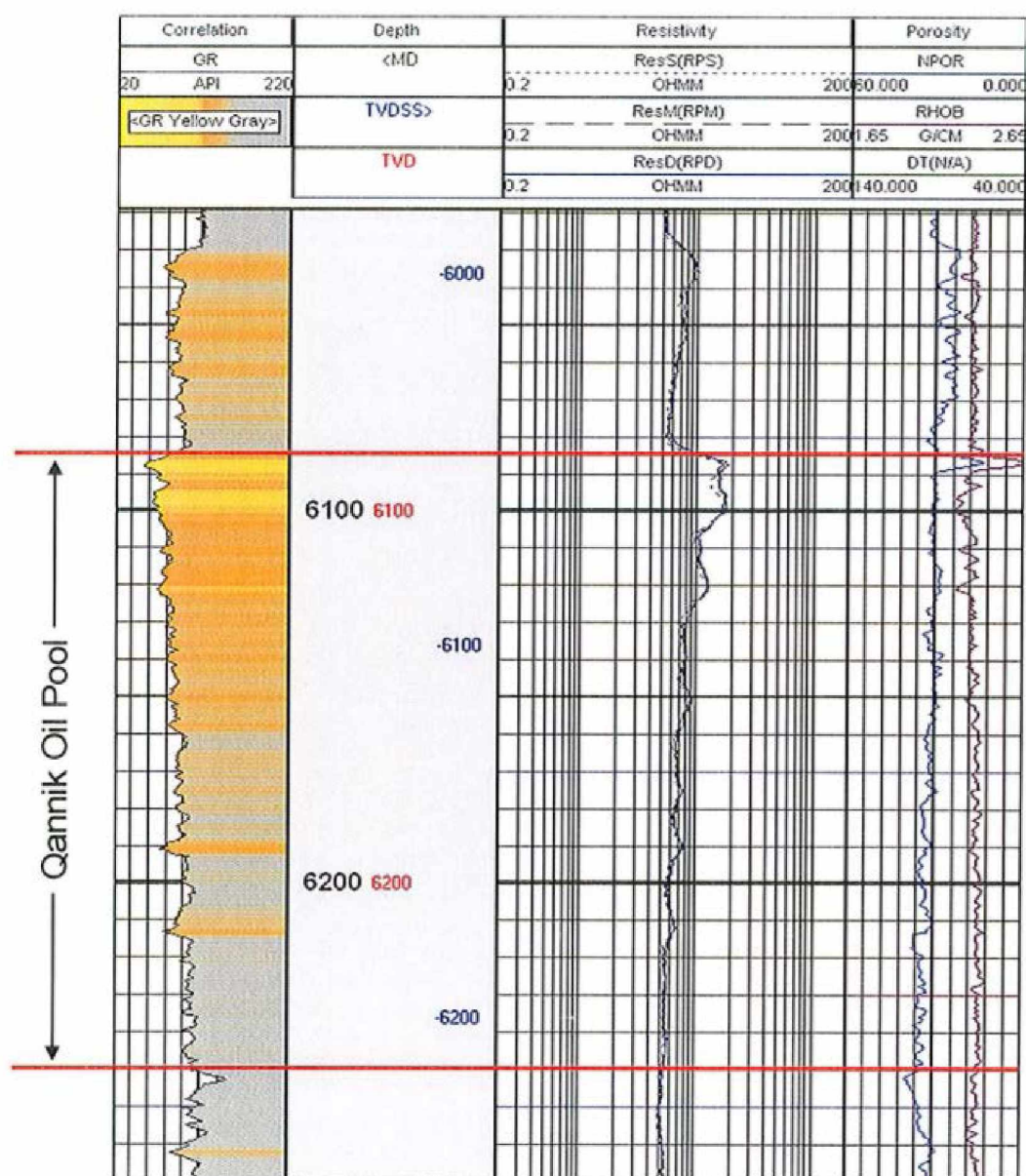


FIGURE 51: QANNIK TYPE LOG (AOGCC, 2008)

TABLE 4: QANNIK OIL IN PLACE AND RECOVERABLE VOLUMES (AOGCC, 2008)

Hydrocarbon Volume	Nine-Well Development (MMSTB)	Eighteen-Well Development (MMSTB)
Original Oil in Place (OOIP)	79	127
Primary Recovery with Gas Cap Expansion (Primary) (15% of OOIP)	12	19
Primary + Waterflood (a total of 22% of OOIP)	17	28

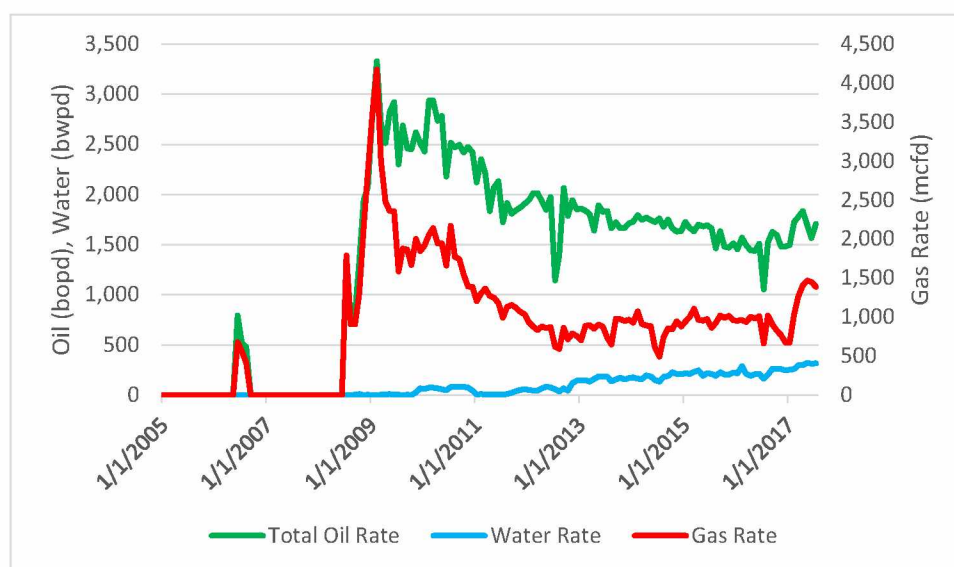


FIGURE 52: QANNIK FIELD PRODUCTION



FIGURE 53: QANNIK PRODUCTION &amp; ACTIVE WELLS

## 9. DUCK ISLAND

Hilcorp is the current operator of the Duck Island unit which consists of the Endicott, Eider, Sag Delta North, and Minke fields, and are produced from the islands Main Production Island (MPI) and Satellite Drilling Island (SDI), west of Greater Prudhoe Bay.

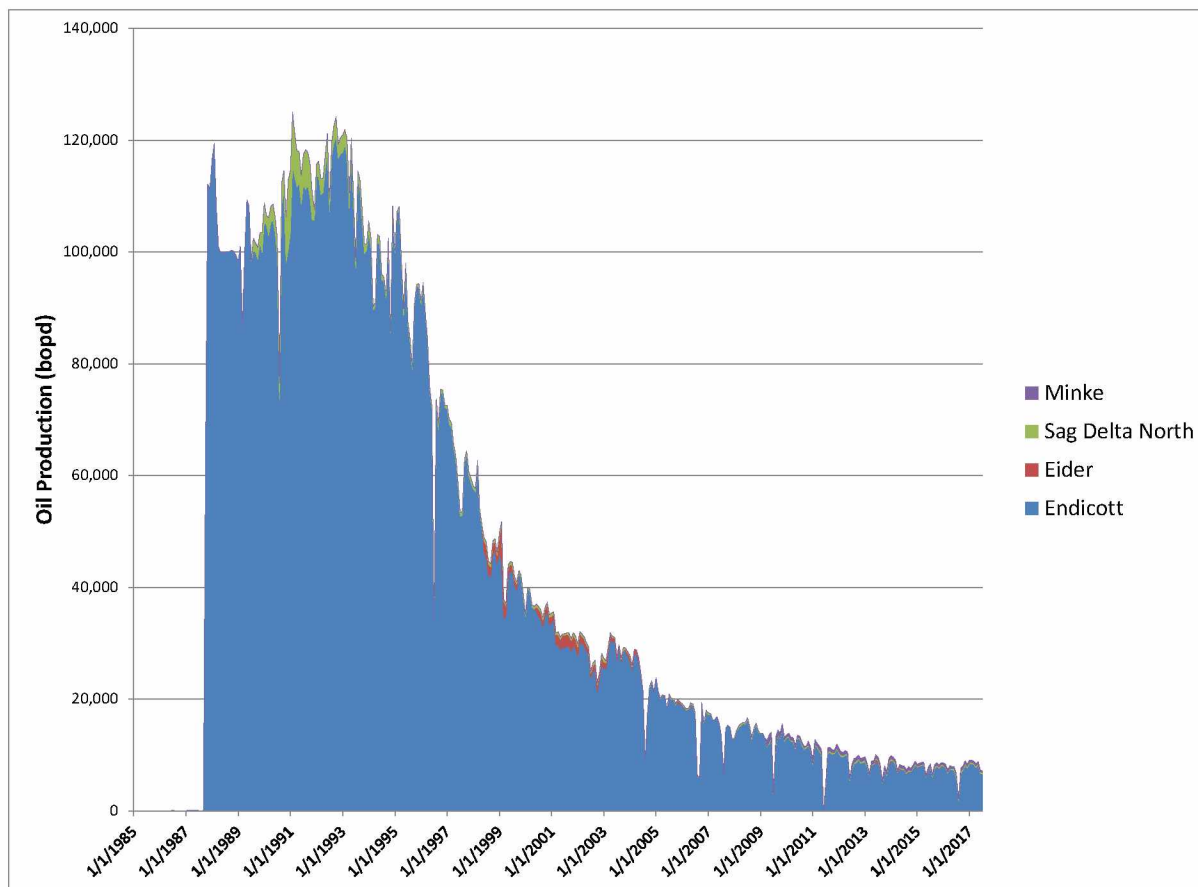


FIGURE 54: DUCK ISLAND UNIT PRODUCTION

### 9.1. EIDER

The Eider field produces from the Ivishak formation and consists of two wells that have produced 2.8 million barrels. Although in 2013 the producer was turned back online, the vast majority of the oil was produced from 1998-2006. Current production average less than 20 barrels of oil per day.



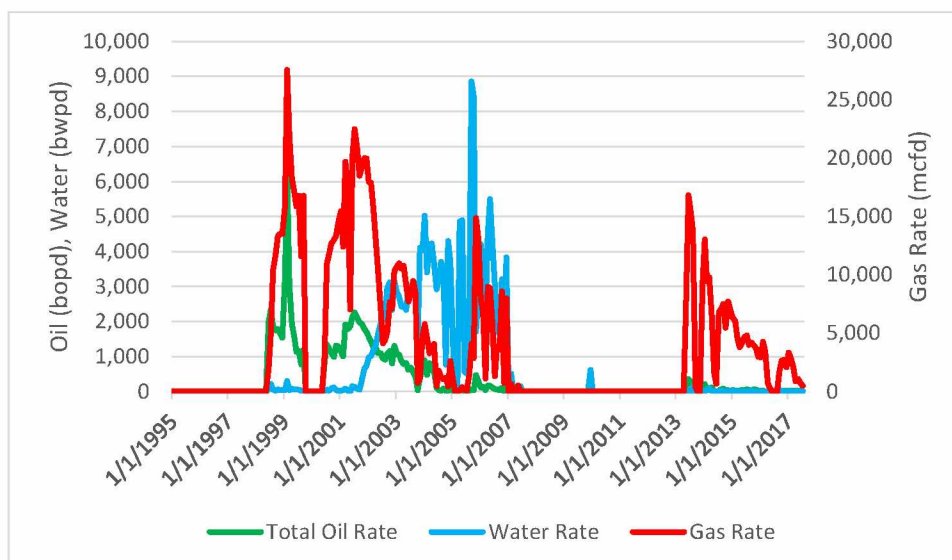


FIGURE 55: EIDER FIELD PRODUCTION

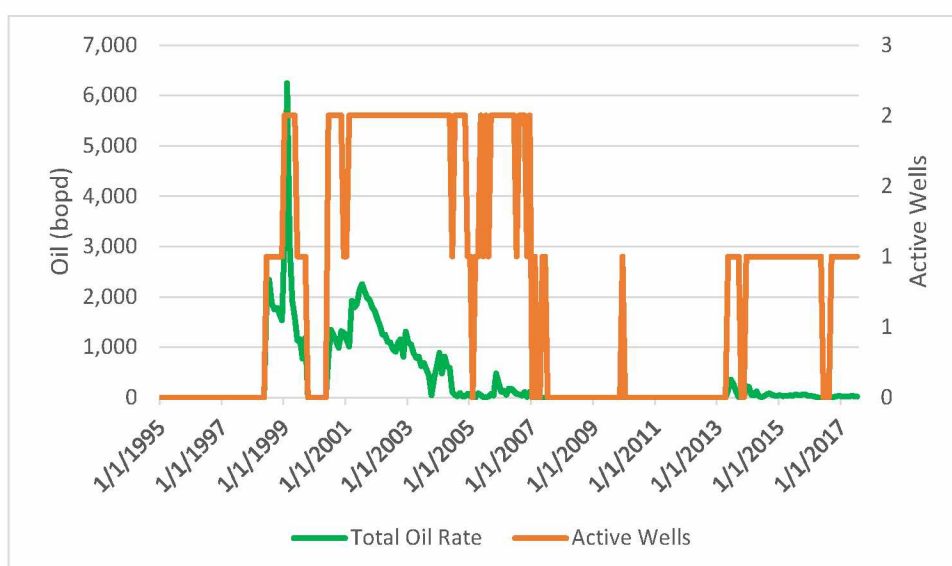


FIGURE 56: EIDER PRODUCTION AND ACTIVE WELLS

## 9.2. ENDICOTT

The Endicott field produces from the Kekiktuk formation and was the first arctic offshore producing oil field, producing from two man-made gravel islands in 14 feet of water (Adamson, Hellman, & Metzger, 1991). Production began in 1998 and peaked around 115,000 bopd. The field has produced just shy of 500 million barrels to date and averages 6,000-7,000 bopd with 70 active wells. It has an initial gas cap and is developed as a waterflood with gas reinjection.

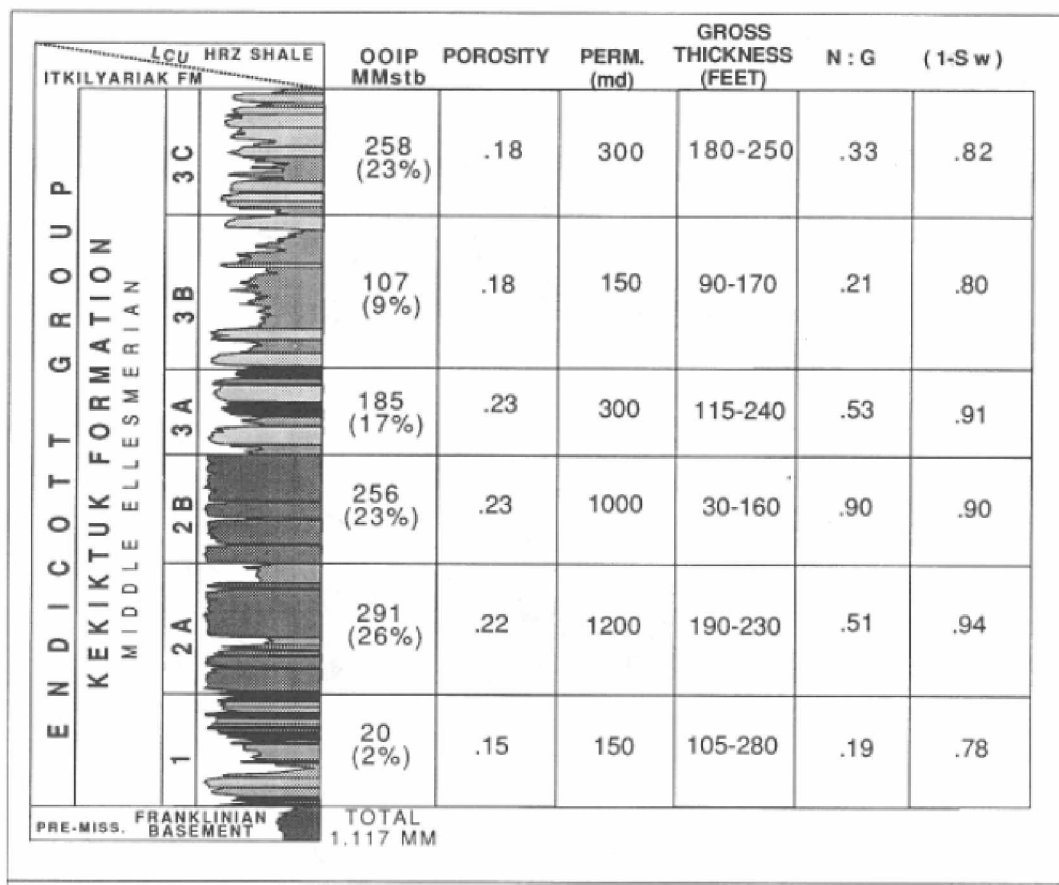


FIGURE 57: ENDICOTT TYPE SECTION (ADAMSON, HELLMAN, &amp; METZGER, 1991)

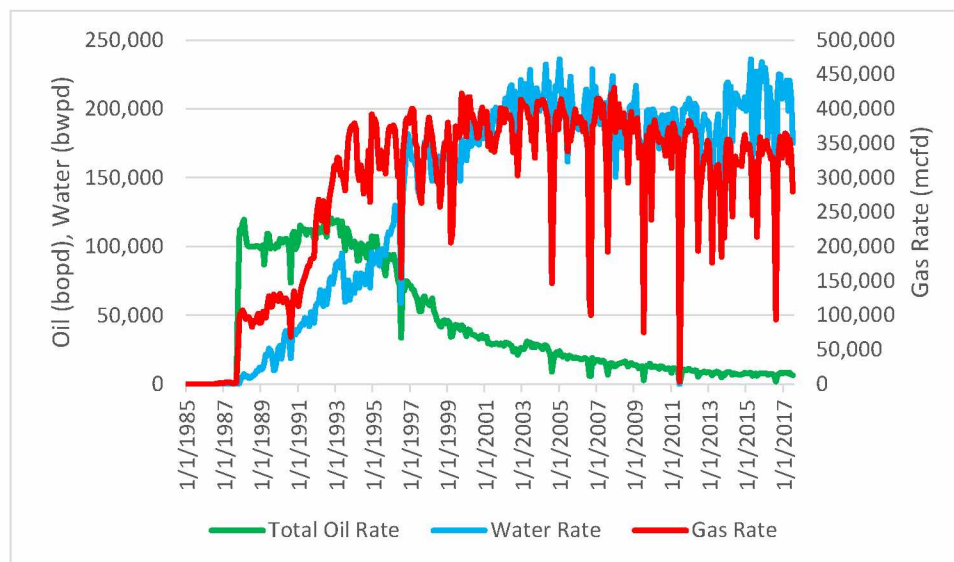


FIGURE 58: ENDICOTT FIELD PRODUCTION



FIGURE 59: ENDICOTT PRODUCTION AND ACTIVE WELLS

### 9.3. SAG DELTA NORTH

Sag Delta North is an Ivishak field that began production in 1989. Production briefly peaked over 12,000 bopd with five wells online; however, the field has been a flat production level between 200-500 bopd since 1996. There are three active wells and the field is currently producing around 300 bopd.

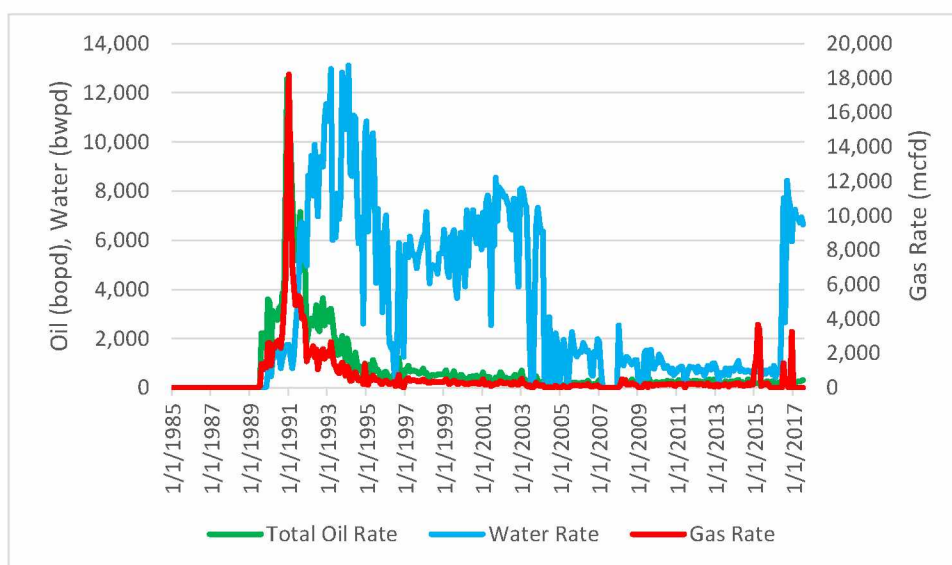


FIGURE 60: SAG DELTA NORTH FIELD PRODUCTION



FIGURE 61: SAG DELTA NORTH PRODUCTION AND ACTIVE WELLS

#### 9.4. MINKE

Minke is a single well (2-30B on MPI) development in the Sag River formation. Production peaked at 1,200 bopd and current production rates are around 400 barrels per day. The well came online in 2009 and has made 1.4 million barrels to date.

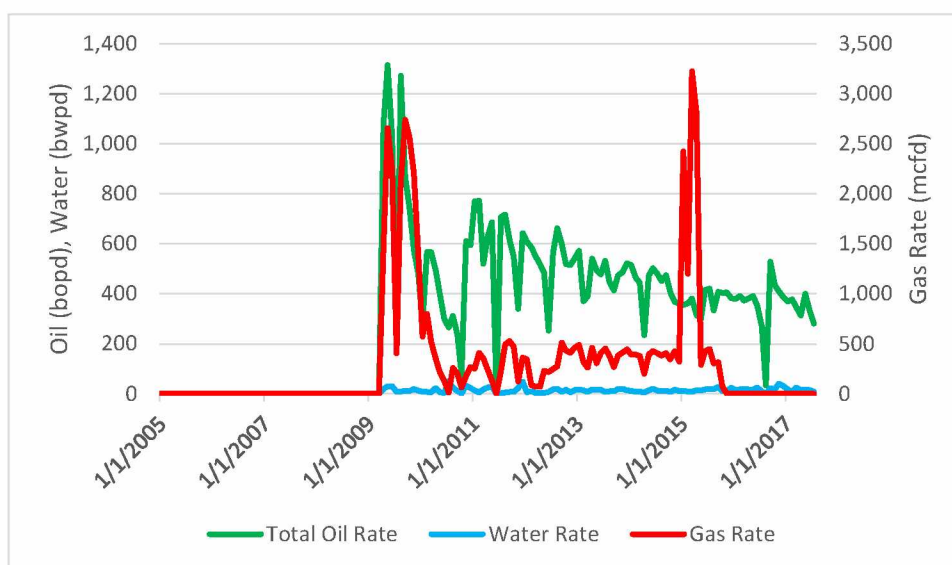


FIGURE 62: MINKE FIELD PRODUCTION

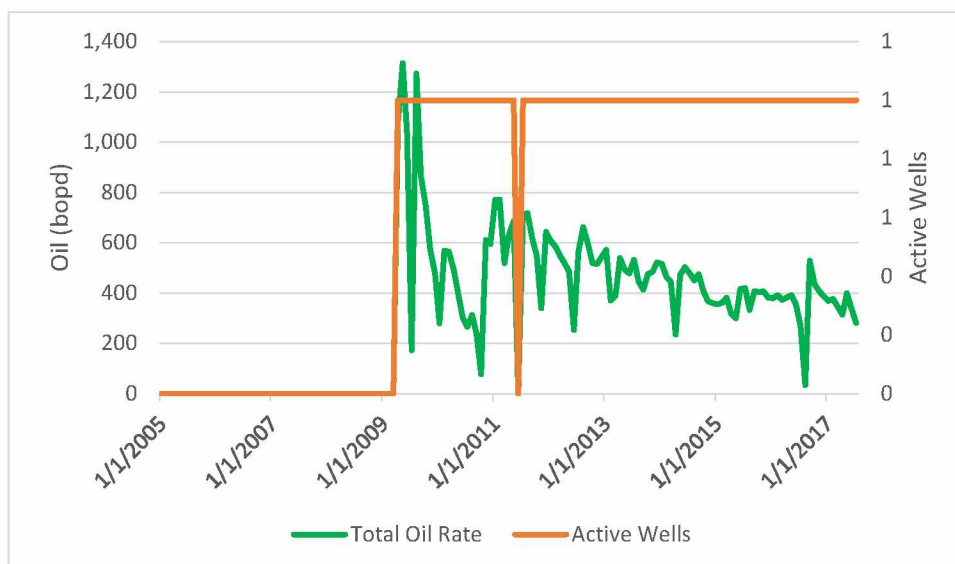


FIGURE 63: MINKE PRODUCTION AND ACTIVE WELLS

## 10. KUPARUK RIVER

The Kuparuk River Unit lies to the west of Prudhoe Bay and is comprised of the Kuparuk, West Sak, Meltwater, Tarn, and Tabasco fields. It is operated by ConocoPhillips, and is the second most productive unit on the North Slope.

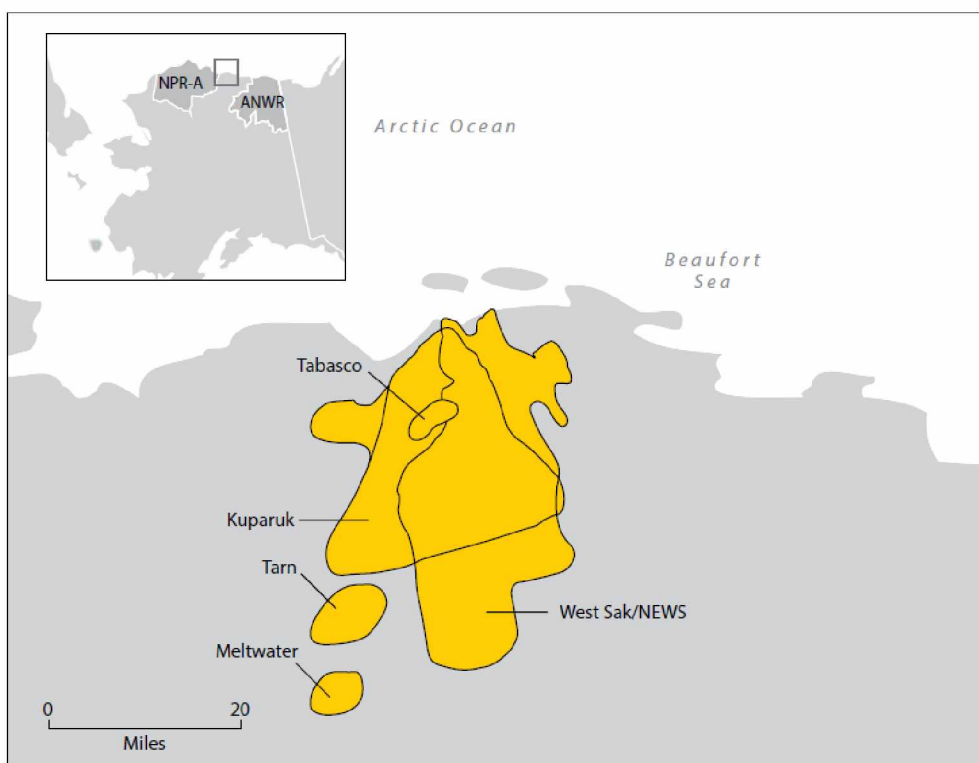


FIGURE 64: KUPARUK RIVER UNIT MAP (CONOCOPHILLIPS, 2017)

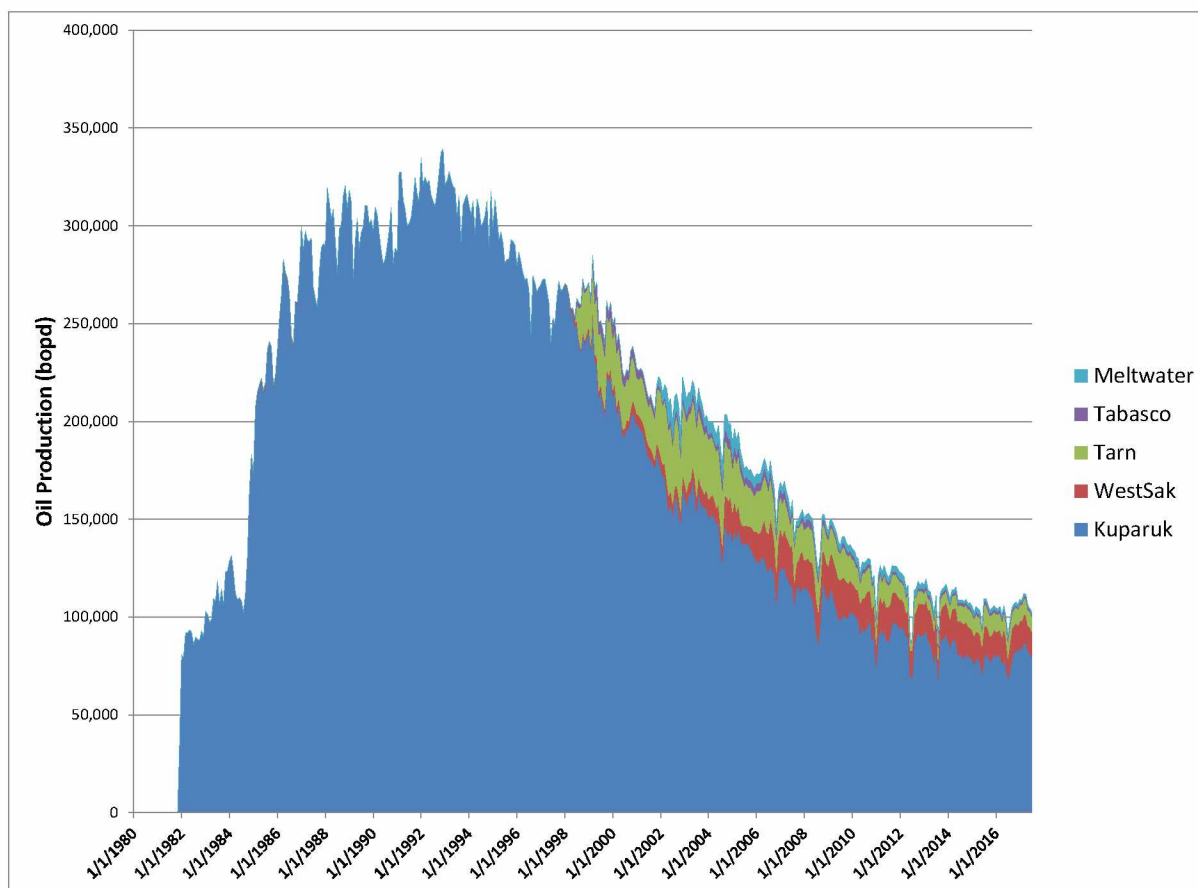


FIGURE 65: KUPARUK RIVER UNIT PRODUCTION

### 10.1. KUPARUK

The Kuparuk River field was discovered in 1969 in the Ugnu No. 1 well, and production began in December 1981, four and a half years after Prudhoe Bay began production (Jensen, et al., 2012). The field is developed as a large scale waterflood and has incorporated both with miscible-water-alternating-gas (MWAG) and immiscible-water-alternating-gas (IWAG) projects to enhance oil recovery. The field produces from the Kuparuk formation, including the A and C sands, and is highly faulted. The original anticipated rates for the field were 250,000 bopd (Jensen, et al., 2012). The field peaked at over 325,000 bopd, and sustained production above 250,000 bopd until 1998. The field has made 2.4 billion barrels of oil to day and currently produces around 80,000 bopd from approximately 800 active wells, with over 1,100 wells having been drilled into the field.



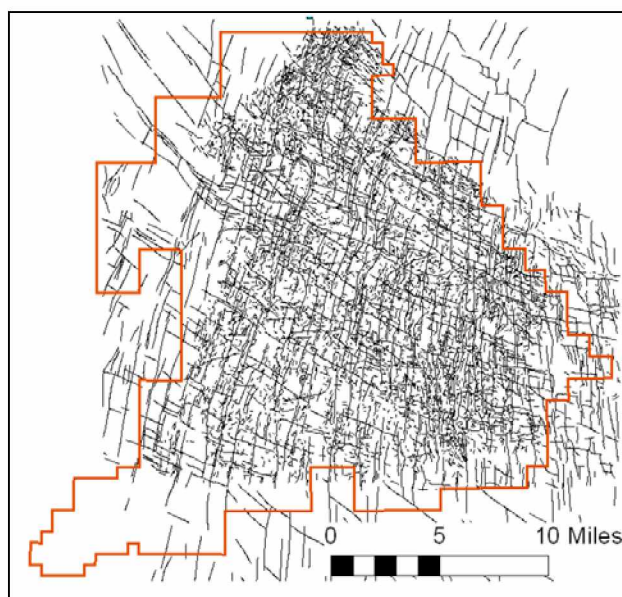


FIGURE 66: KUPARUK FAULT MAP (JENSEN, ET AL., 2012)

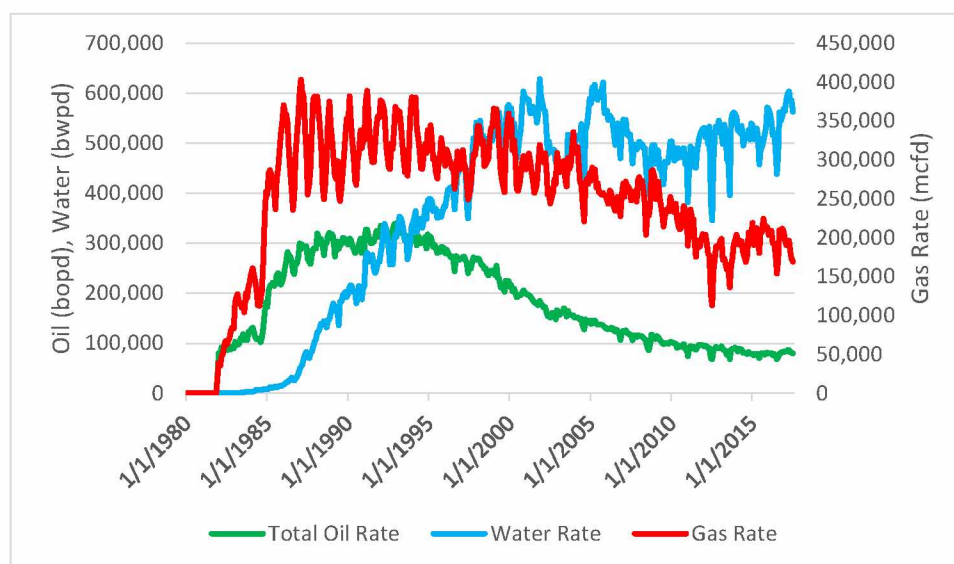


FIGURE 67: KUPARUK FIELD PRODUCTION

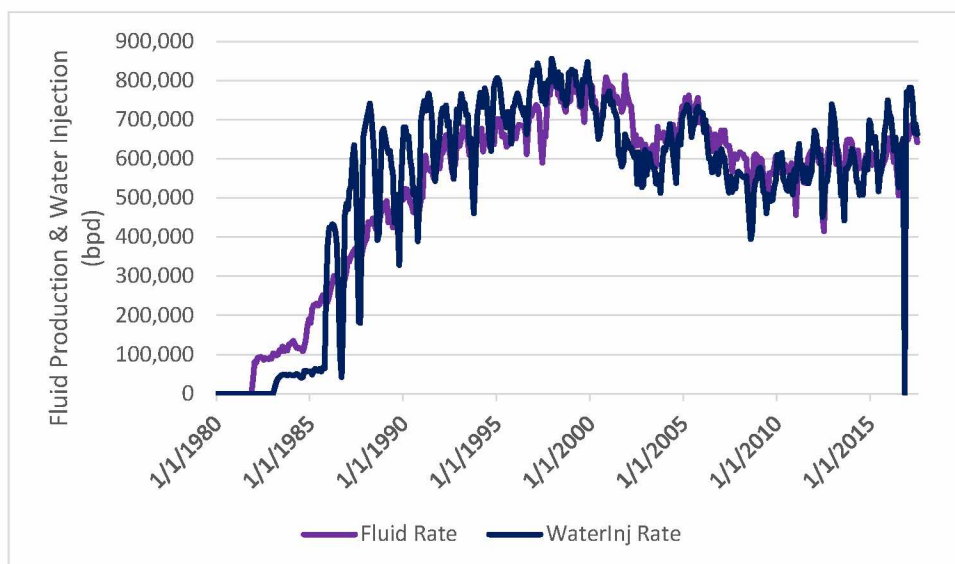


FIGURE 68: KUPARUK FLUID PRODUCTION AND WATER INJECTION RATE

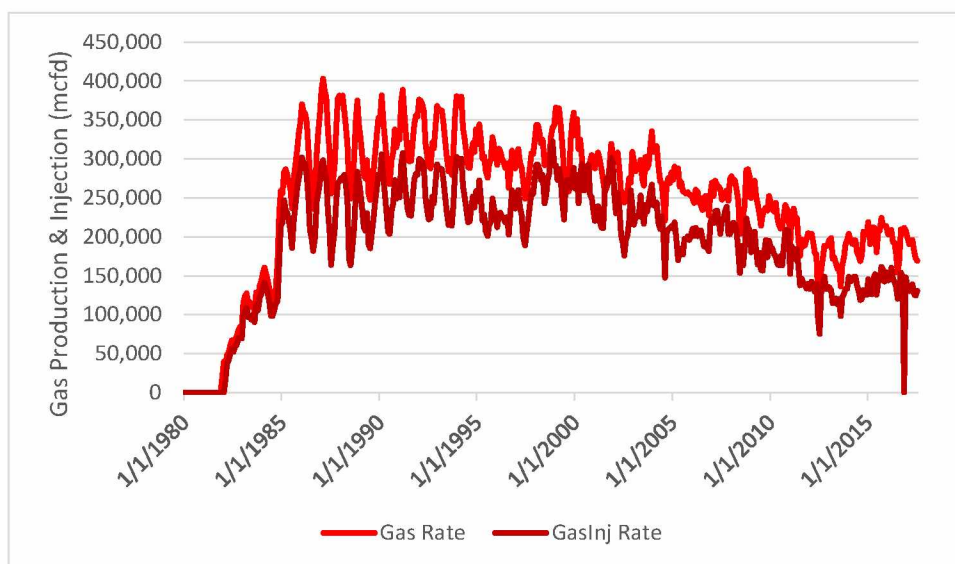


FIGURE 69: KUPARUK GAS PRODUCTION AND INJECTION RATE



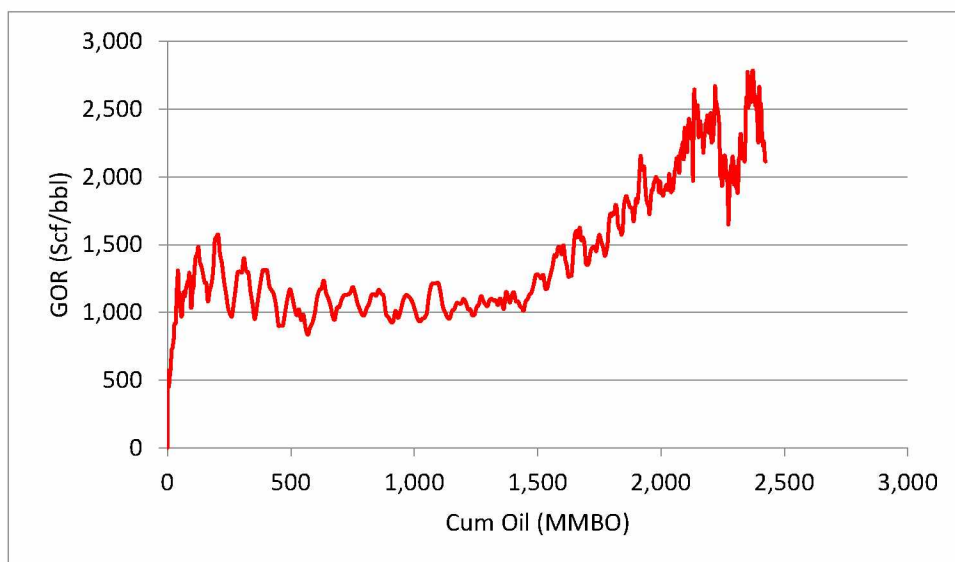


FIGURE 70: KUPARUK GAS OIL RATIO VS. CUM OIL

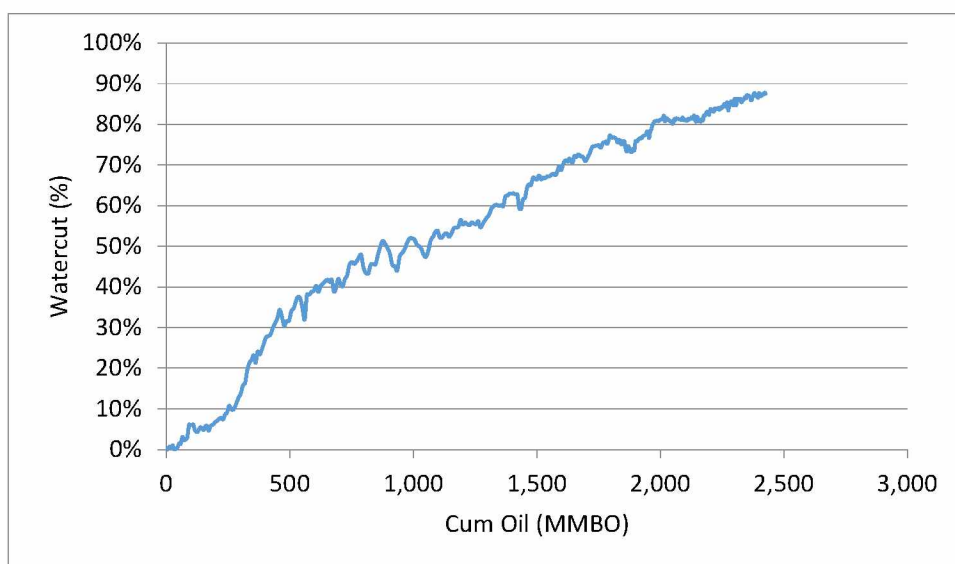


FIGURE 71: KUPARUK WATERCUT VS. CUM OIL

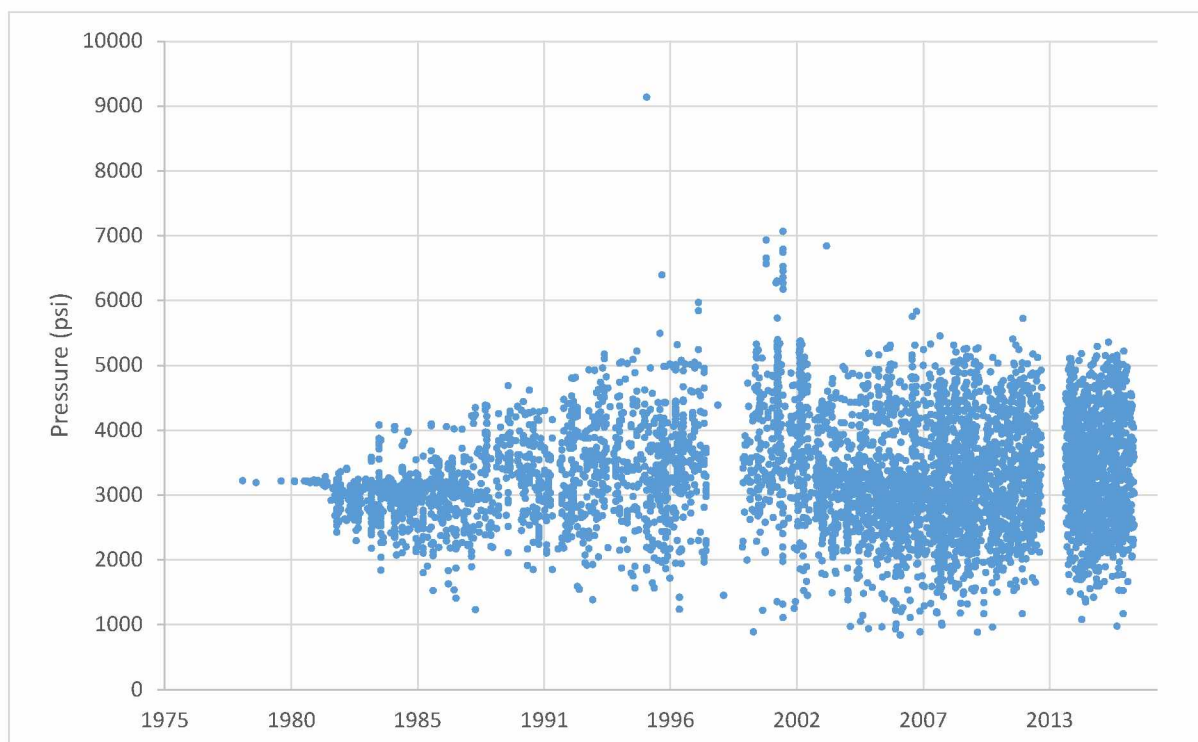


FIGURE 72: KUPARUK PRESSURES

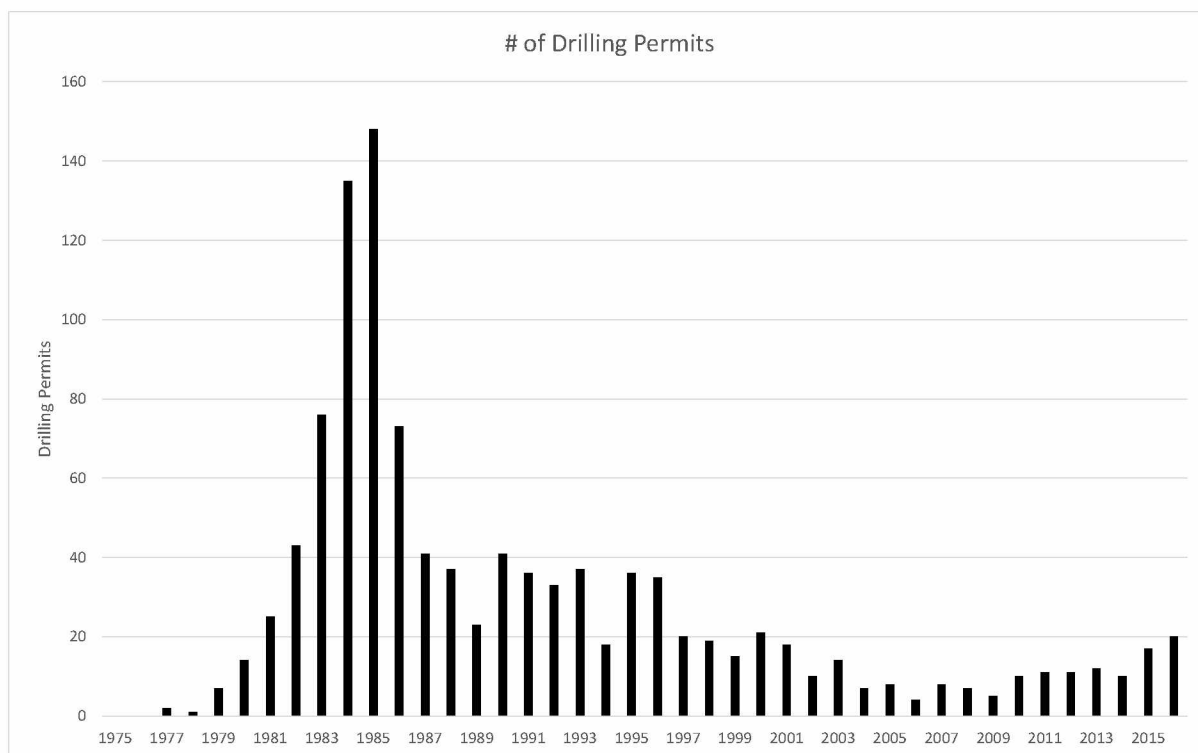


FIGURE 73: KUPARUK DRILLING PERMITS BY YEAR

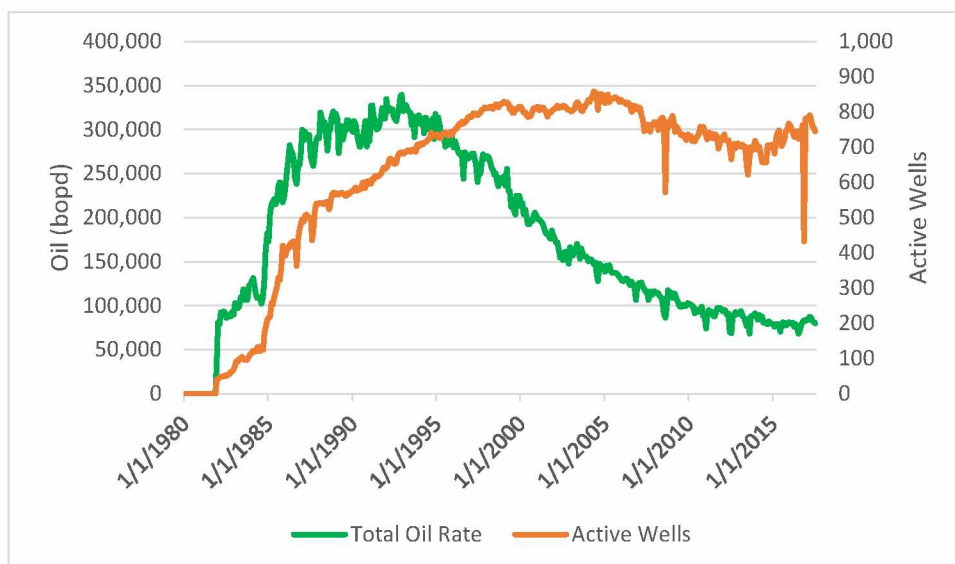


FIGURE 74: KUPARUK PRODUCTION AND ACTIVE WELLS

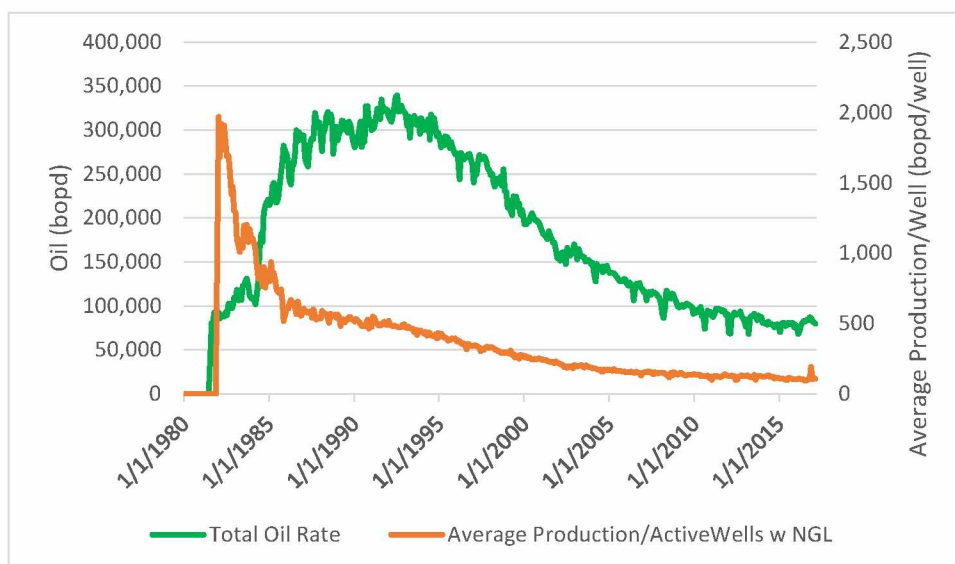


FIGURE 75: KUPARUK AVERAGE ACTIVE WELL PRODUCTION

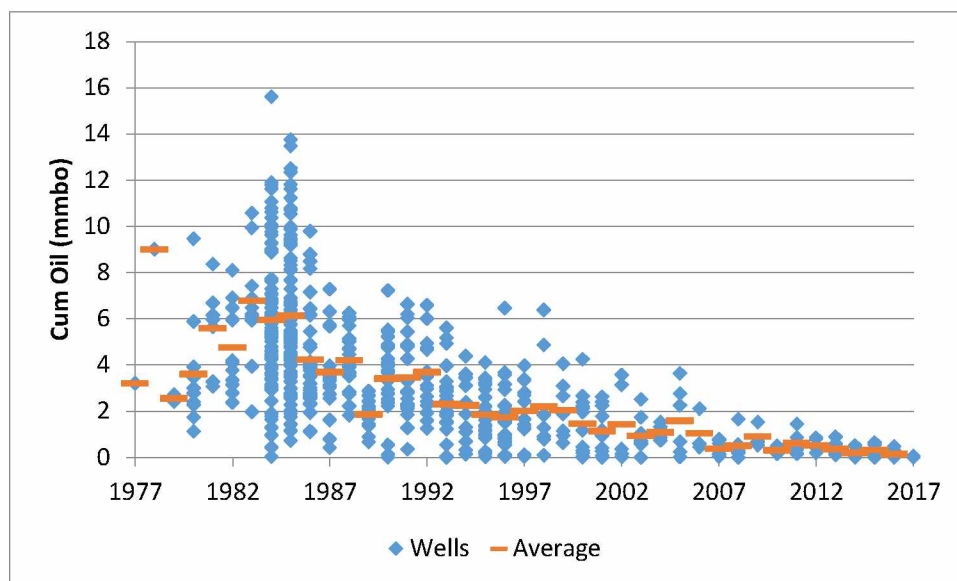


FIGURE 76: KUPARUK WELL CUM OIL TO DATE BY PERMIT YEAR

## 10.2. MELTWATER

The Meltwater field was discovered in early 2000 with the Meltwater North 1 well, and came on production in November 2001 (AOGCC, 2017). It produces from the Bermuda interval of the Seabee formation, and no gas cap or oil water contacts have been encountered in the pool (AOGCC, 2017). Production peaked in this field over 10,000 bopd and it currently produces around 1,000 bopd from 14 active wells.

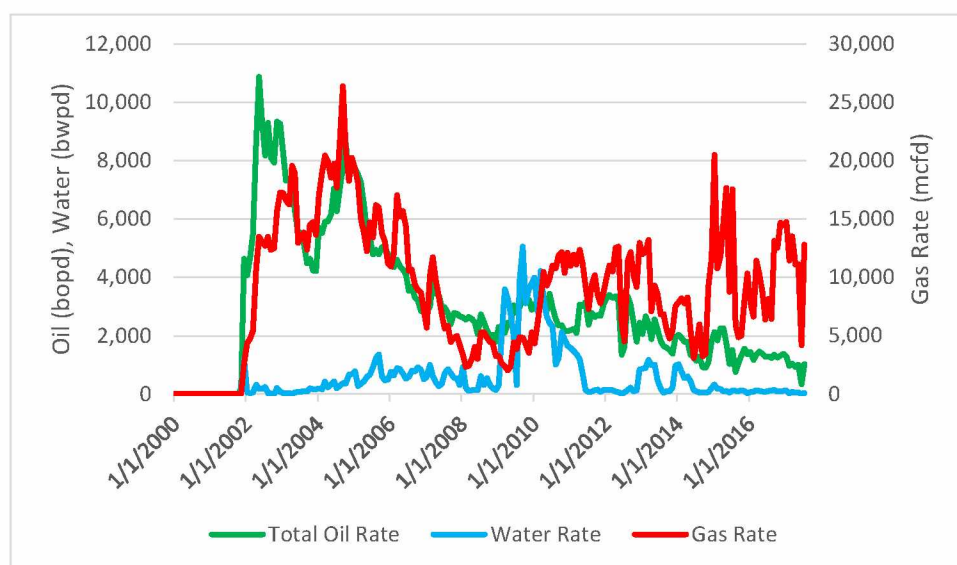


FIGURE 77: MELTWATER FIELD PRODUCTION

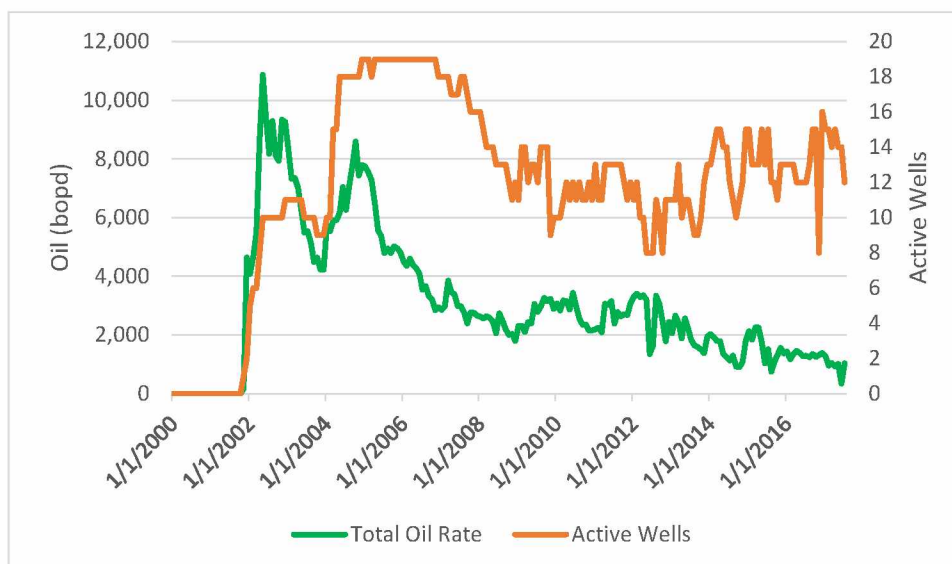


FIGURE 78: MELTwater PRODUCTION AND ACTIVE WELLS

### 10.3. TABASCO

The Tabasco field was discovered 1986 and produces from the Tabasco sandstone, a Schrader Bluff equivalent (AOGCC, 2017). Field production began in 1998 and peaked at around 7,000 bopd. The field 19 million barrels of oil to day and is currently producing around 1,000 bopd from 7 active wells.

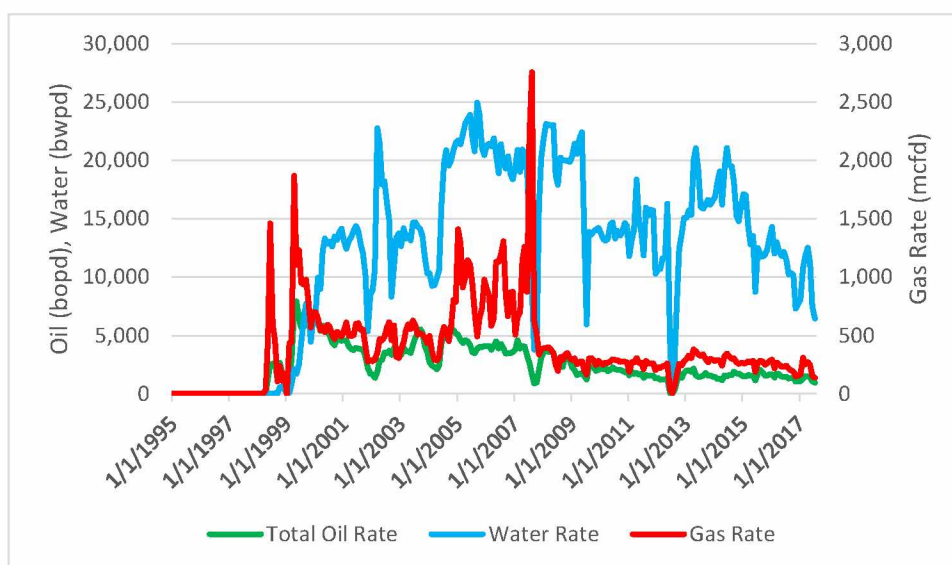


FIGURE 79: TABASCO FIELD PRODUCTION

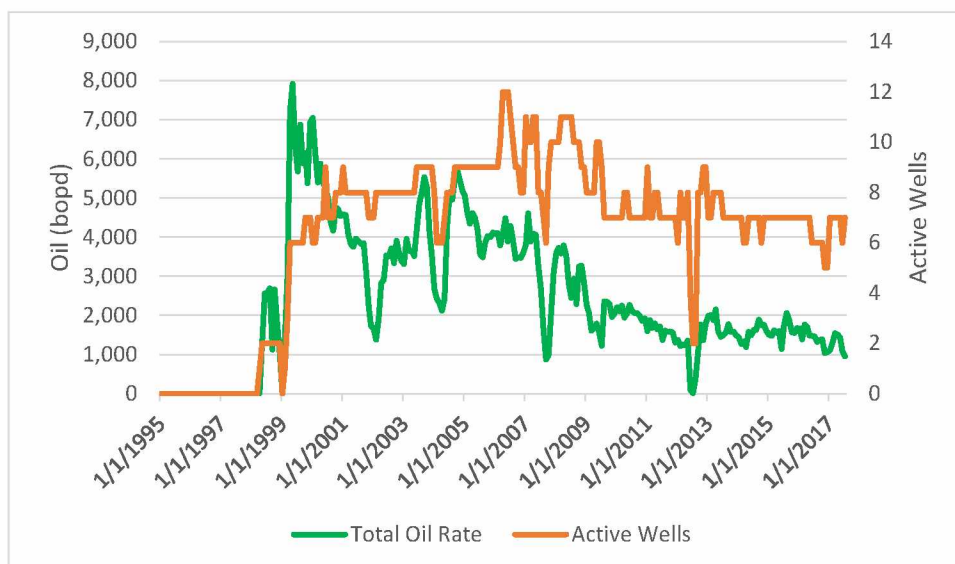


FIGURE 80: TABASCO PRODUCTION AND ACTIVE WELLS

#### 10.4. TARN

The Tarn field was discovered in 1991 with the Bermuda No 1 well, and produces from the Seabee formation (AOGCC, 2017). Production began in 1998 and peaked over 35,000 bopd. The field has produced 118 million barrels of oil, and is currently producing approximately 8,000 bopd from 60 active wells.

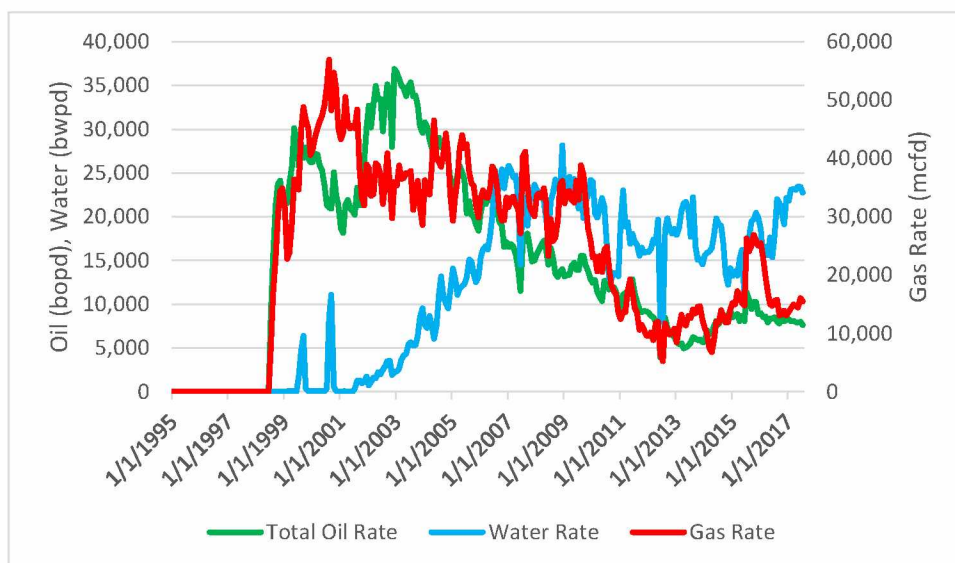


FIGURE 81: TARN FIELD PRODUCTION

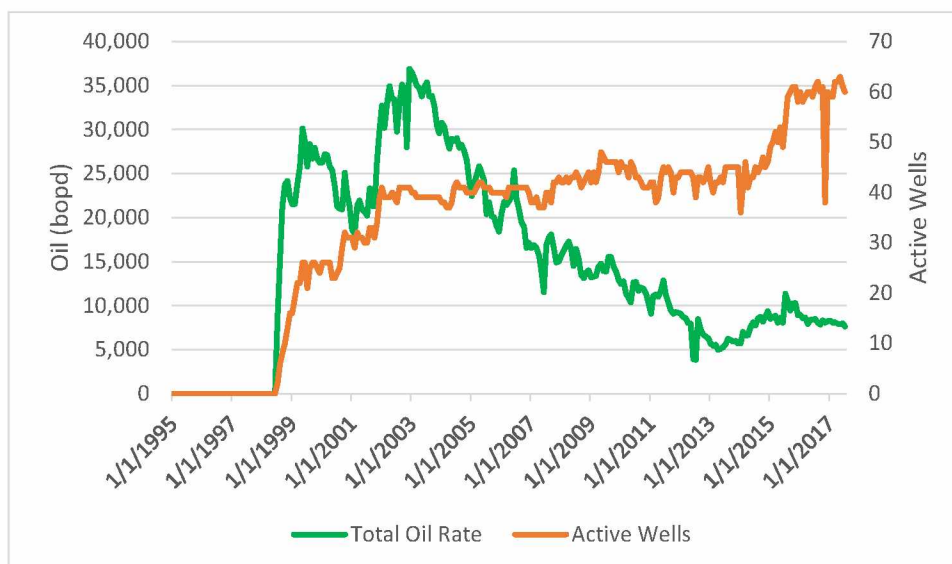


FIGURE 82: TARN PRODUCTION AND ACTIVE WELLS

## 10.5. WEST SAK

The West Sak Field is a multi-billion barrel of oil in place viscous oil reservoir that produces from the West Sak sands, also referred to as Schrader Bluff. In 1983, a West Sak pilot waterflood operated for two and a half years. Although it was a technical success, it was considered a business failure at the time due to the low production rates (Foerster, Lynch, Stramp, Werner, & Thompson, 1997). Production from the field began again in 1997, with early development consisted vertical wells and averaged of 150-250 bopd per producer. Using horizontal drilling and multi-lateral wells, peak rates of over 5,000 bopd and sustained rates of 1,500 were achieved (Targac, Redman, Davis, McKeever, & Chambers, 2005). The field has produced 84 million barrels of oil and currently produces approximately 14,000 bopd from 80-90 active wells.

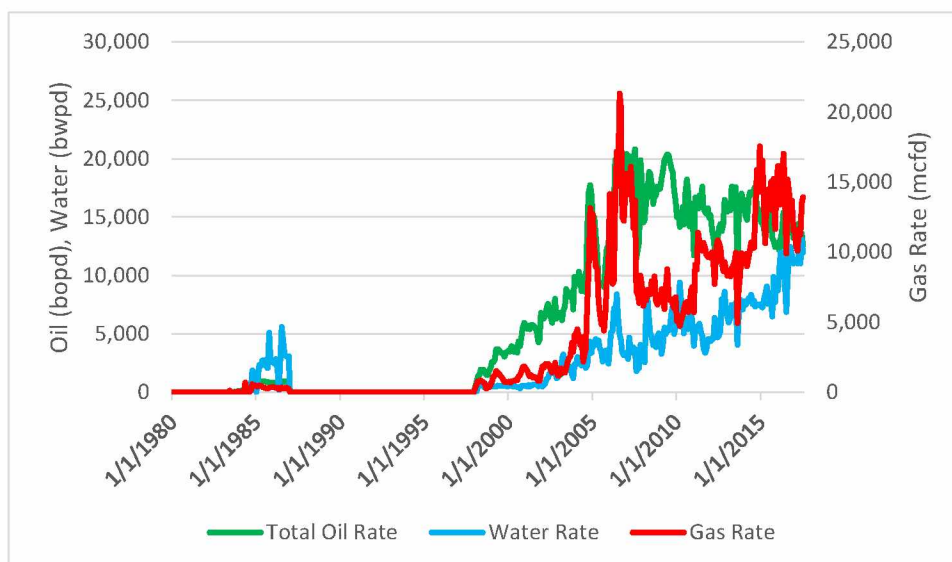


FIGURE 83: WEST SAK FIELD PRODUCTION



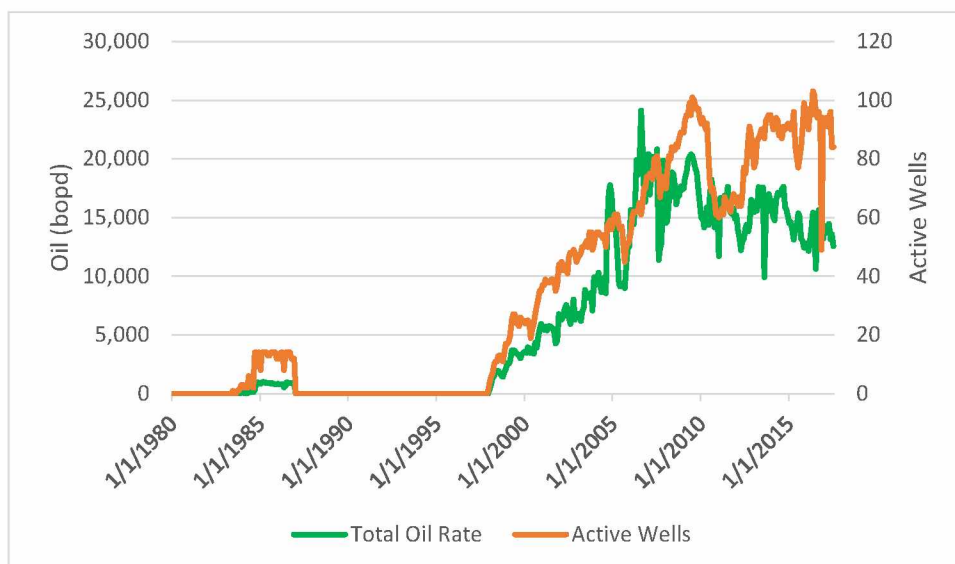


FIGURE 84: WEST SAK PRODUCTION AND ACTIVE WELLS

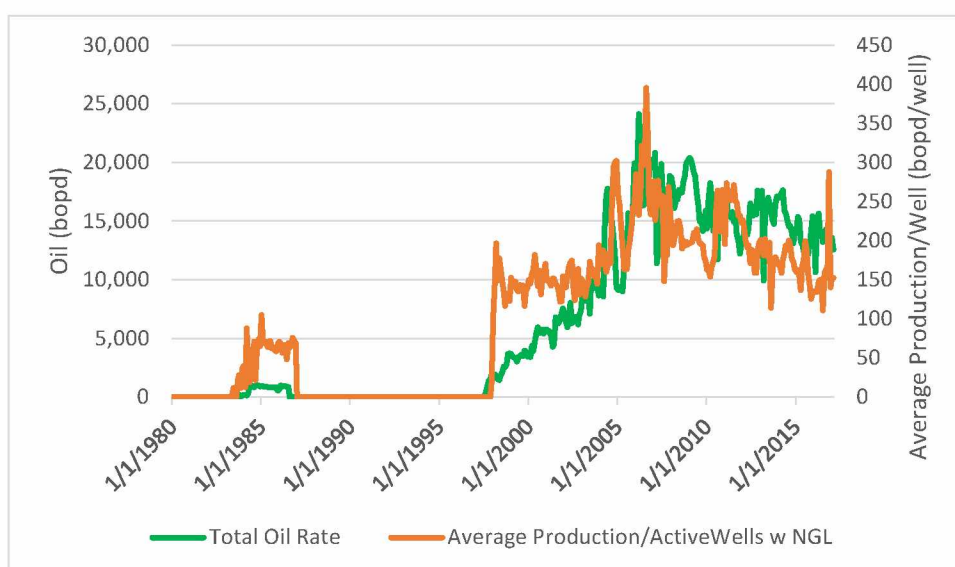


FIGURE 85: WEST SAK AVERAGE PRODUCTION/ACTIVE WELL

## 11. MILNE POINT

The Milne Point unit is located to the northwest of Prudhoe Bay along the coast and is operated by Hilcorp. It consists of four pools, identified by their producing formation, the Kuparuk, Schrader Bluff, Sag River, and Ugnu.



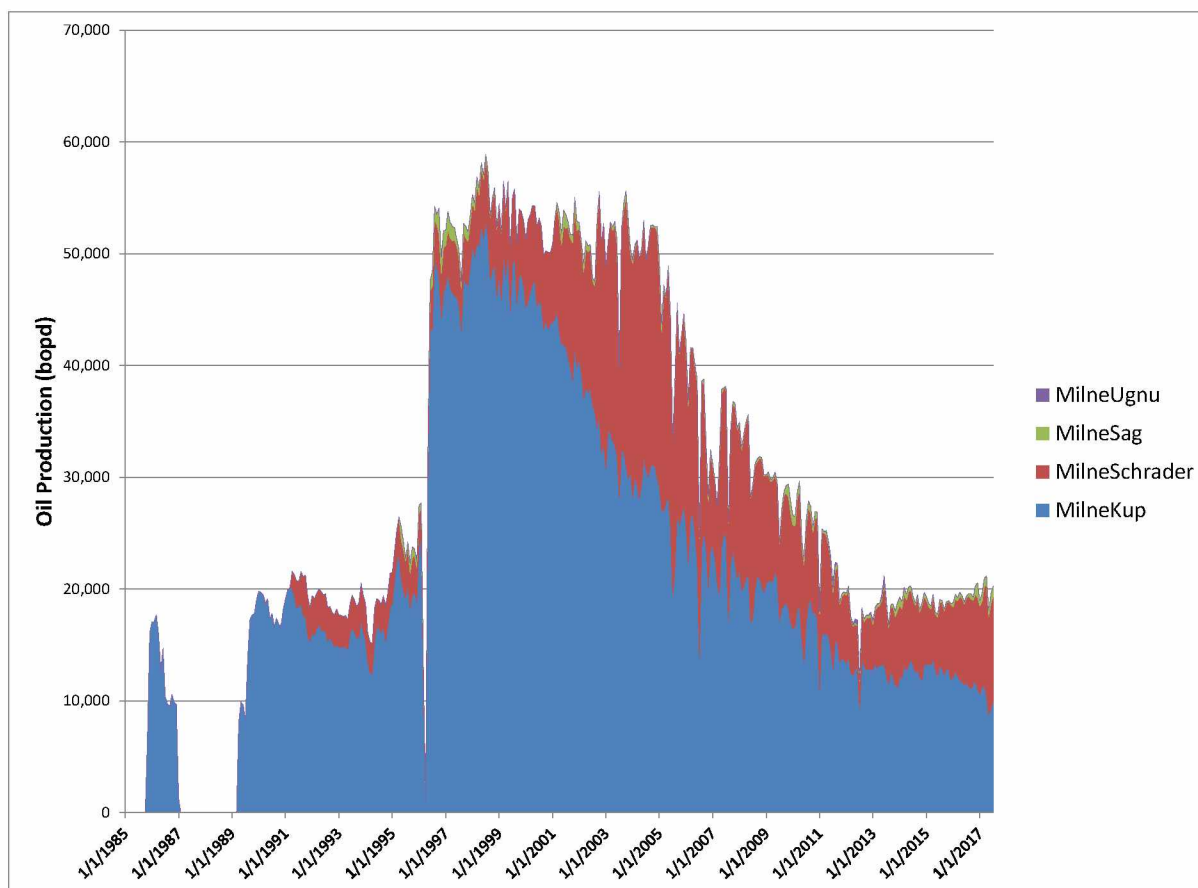


FIGURE 86: MILNE POINT UNIT PRODUCTION

### 11.1. MILNE KUPARUK

The Milne Kuparuk was discovered in 1969 with the Kavarak Pt. No 32-25 well. Production began in 1985, but with low oil prices the field was shut down in 1987 before resuming in 1990 (AOGCC, 2017). Production increased dramatically in 1996 after an aggressive drilling program, more than doubling the previous average rate and peaking near 50,000 bopd. The field has produced 255 million barrels of oil and is currently producing 11,000 bopd from 120-140 wells. Wells in the Milne Kuparuk utilize electric submersible pumps (ESPs) for artificial lift, and ESP replacements create fluctuations on the number of wells online and field rate.

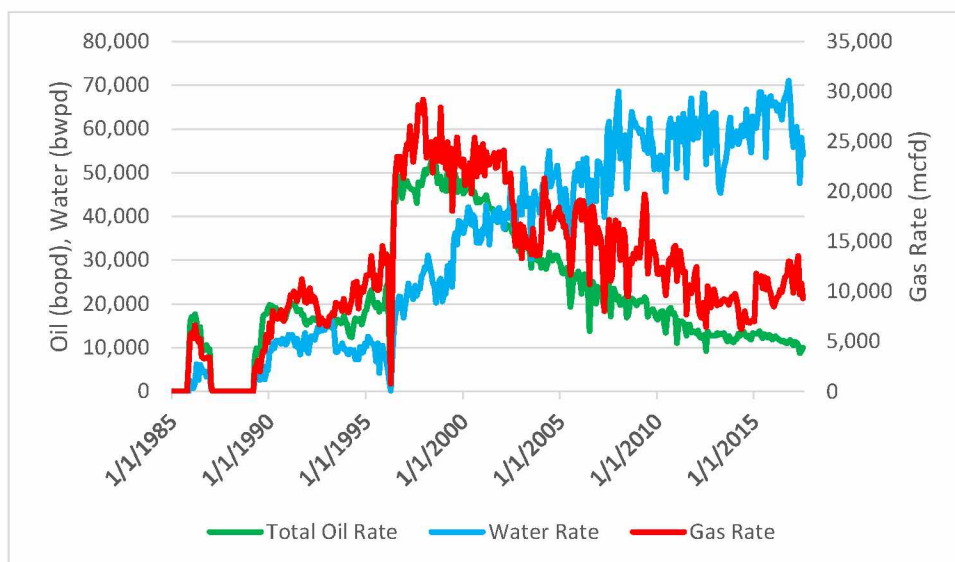


FIGURE 87: MILNE KUPARUK FIELD PRODUCTION

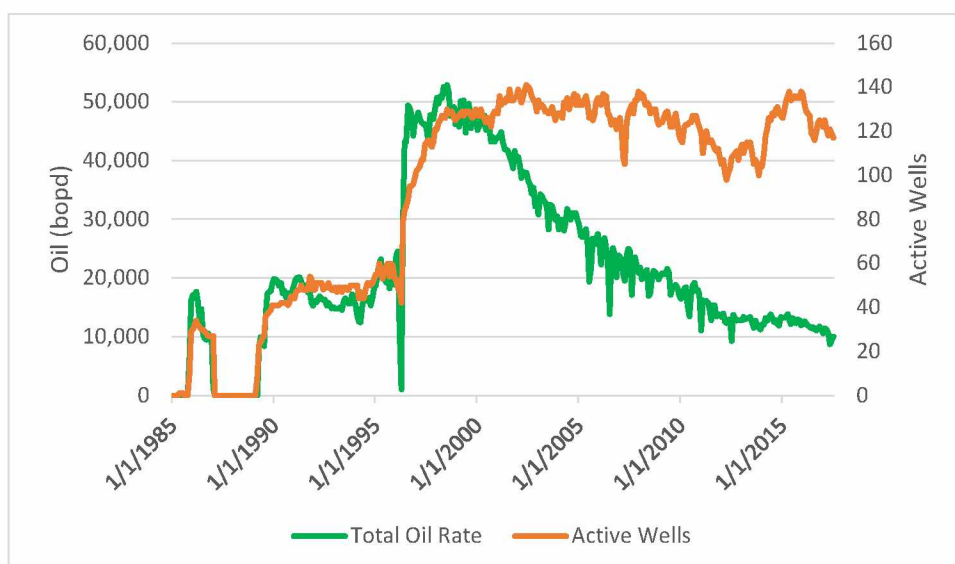


FIGURE 88: MILNE KUPARUK PRODUCTION AND ACTIVE WELLS

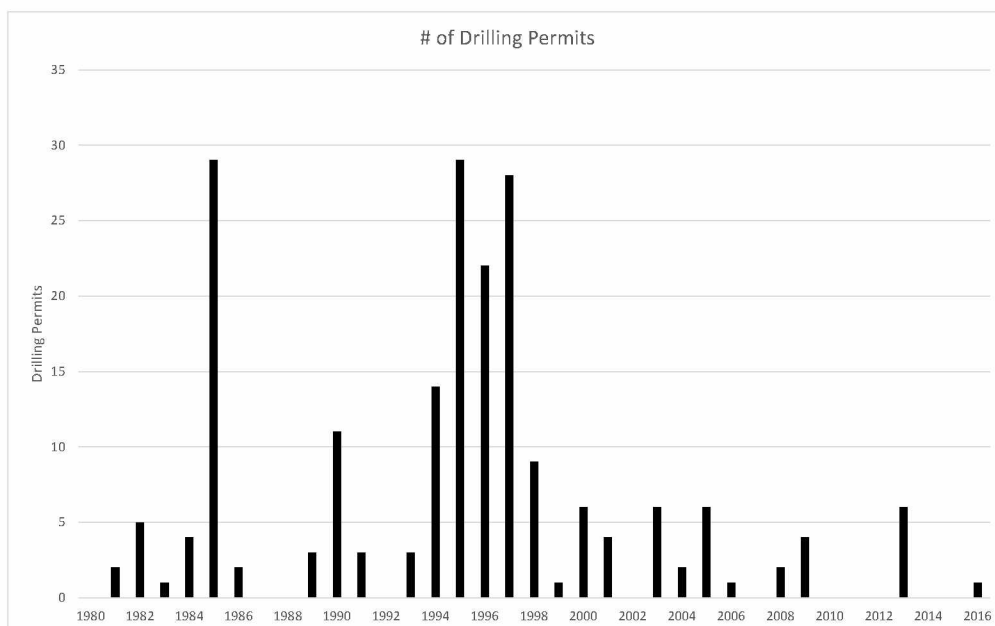


FIGURE 89: MILNE KUPARUK DRILLING PERMITS BY YEAR

## 11.2. MILNE SAG RIVER

The Milne Sag River began production in 1995 producing from the deeper and tighter Sag River formation. Production briefly peaked at 2,000 bopd, and the field has made nearly 3 million barrels to date. Recent activity in this pool has increased production to around 1,000 barrels per day from 5 wells.

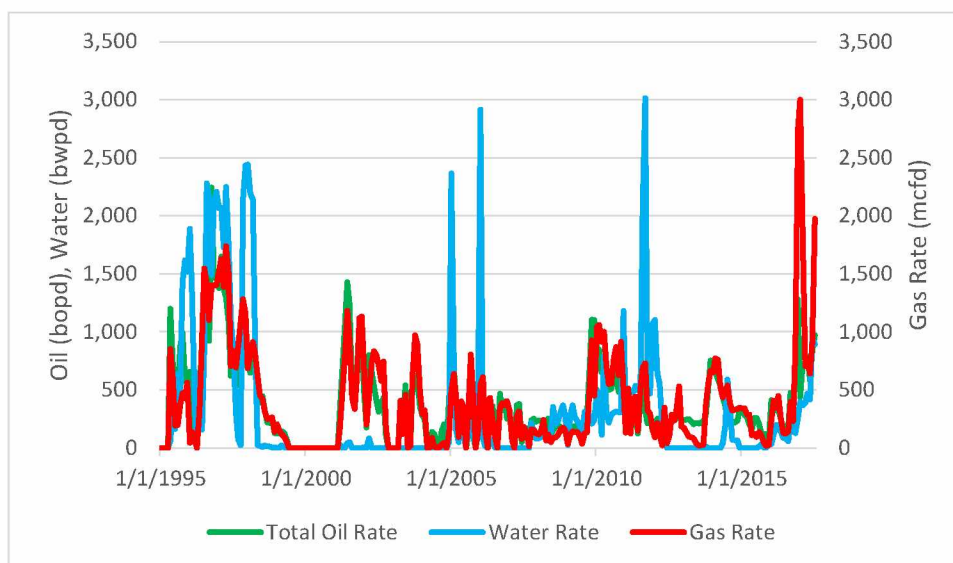


FIGURE 90: MILNE SAG FIELD PRODUCTION

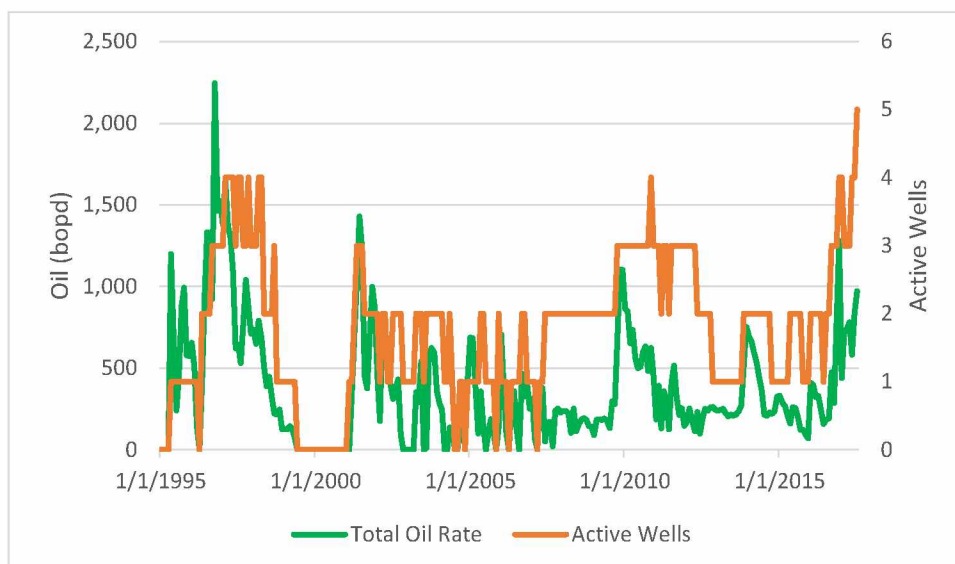


FIGURE 91: MILNE SAG PRODUCTION AND ACTIVE WELLS

### 11.3. MILNE SCHRADER BLUFF

The Milne Schrader Bluff field began production in 1991 and ramped up to over 20,000 bopd in 2004. The field has produced 77 million barrels and recent activity has increased active well count and production from a low of 40 wells producing 4,000 bopd to 80 wells producing over 9,000 bopd.

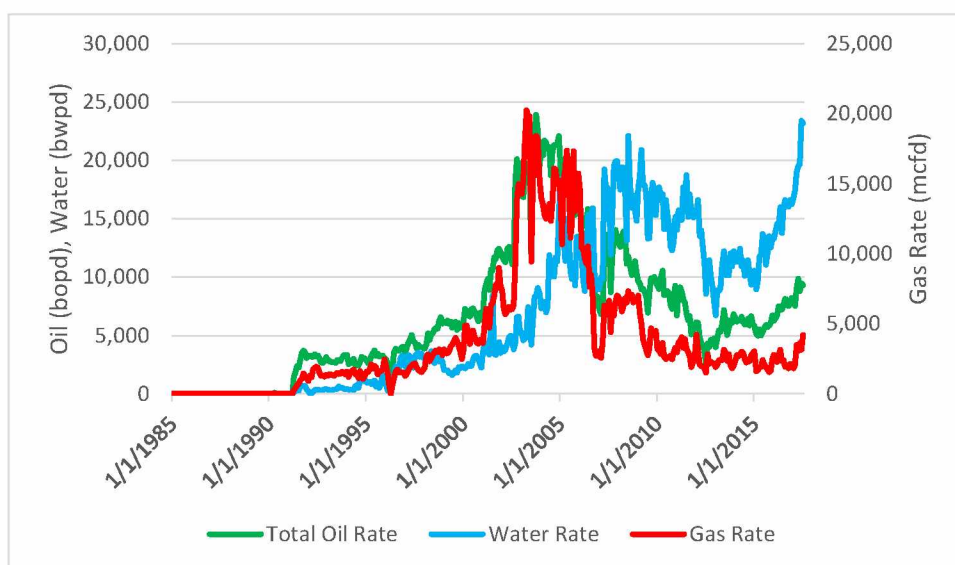


FIGURE 92: MILNE SCHRADER BLUFF FIELD PRODUCTION



FIGURE 93: MILNE SCHRADER BLUFF PRODUCTION AND ACTIVE WELLS

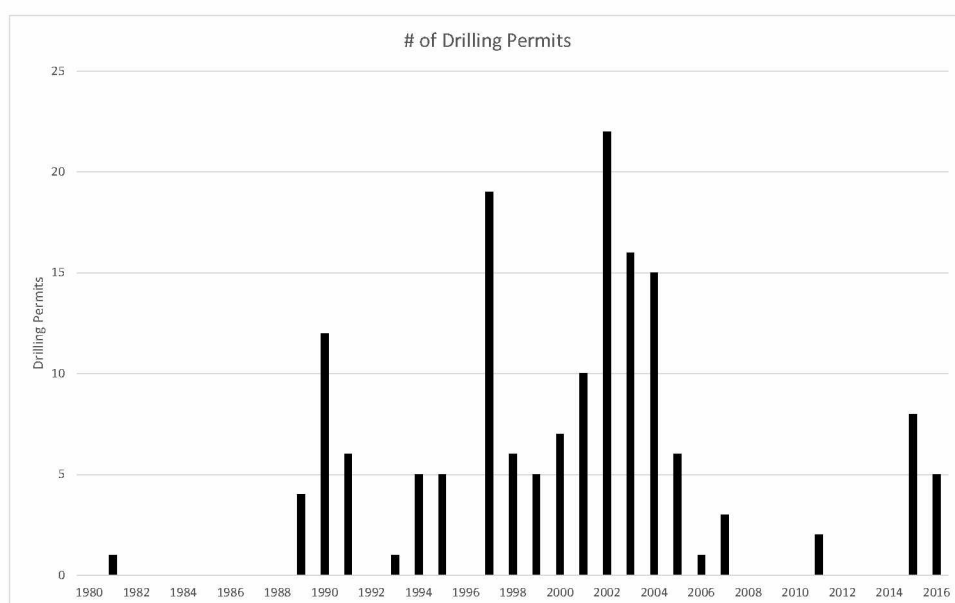


FIGURE 94: MILNE SCHRADER BLUFF DRILLING PERMITS BY YEAR

#### 11.4. MILNE UGNU

The Milne Ugnu pool produces from a dedicated facility located at Milne Point that was designed to handle the heavy viscous crude and separate the associate produced sand. The program was designed to produce the cold heavy oil with sand (CHOPS), and utilized progressive cavity pumps in the wells for artificial lift. The sand production and well deviation created wear in the wells and reduced reliability. Production occurred from 2011-2013, peaking at less than 500 with two wells online.

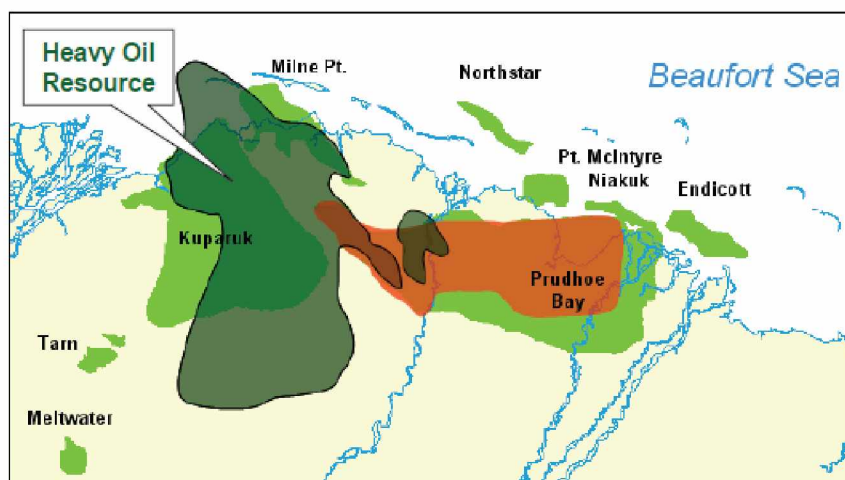


FIGURE 95: NORTH SLOPE HEAVY OIL RESOURCE MAP (YOUNG, MATHEWS, & HULM, 2010)

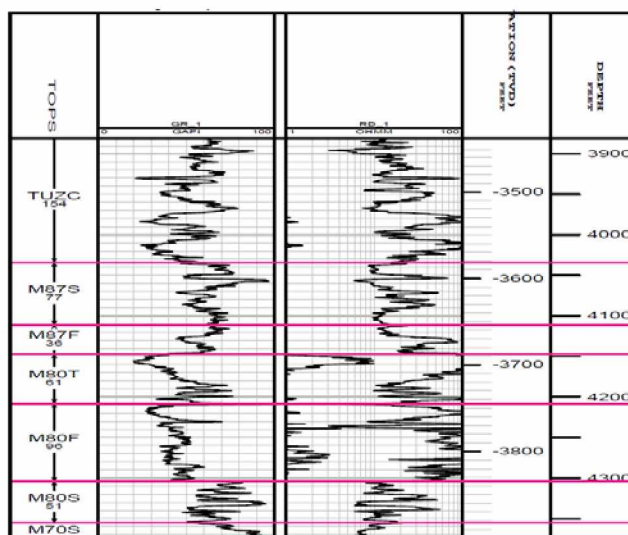


FIGURE 96: MILNE UGNU TYPE LOG (YOUNG, MATHEWS, & HULM, 2010)

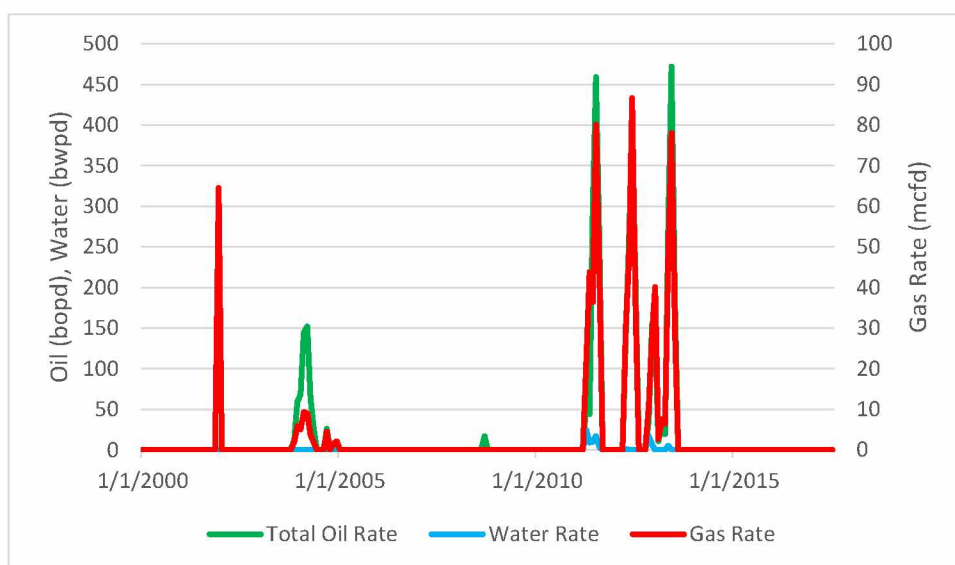


FIGURE 97: MILNE UGNU FIELD PRODUCTION

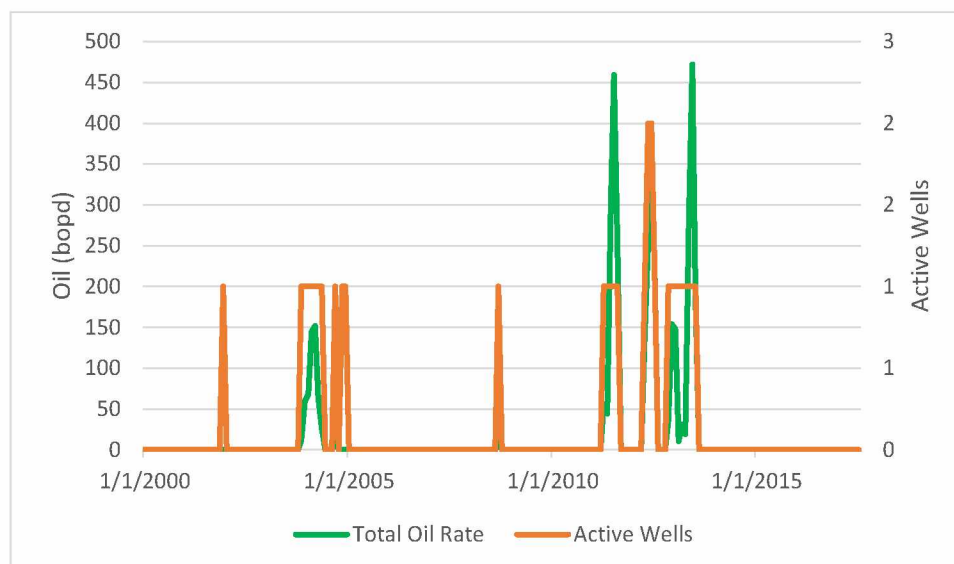


FIGURE 98: MILNE UGNU PRODUCTION AND ACTIVE WELLS

## 12. NIKAITCHUQ

The Nikaitchuq field is located in about 10 feet of water in the Beaufort Sea to the north of the Kuparuk Field and west of Milne Point. The field has a dedicated processing facility and produces from the offshore drill site at Spy Island (SID), and an onshore drillsite at Oliktok Point (OPP) (Kuck, Nofziger, Gentil, & Faevelen, 2014). Kerr-McGee discovered the field in 2004 with the drilling Nikaitchuq No. 1, and ENI acquired 100% ownership in 2007 (Abahusayn, Foster, Brink, Kuck, & Longo, 2012). It comprises of 11 state leases and about 21,000 acres (ENI US Operating Co. Inc., 2017). Nikaitchuq has a royalty average of 15.73%, however successfully was able to petition for modification to 5% to improve the economics of the project after a previous request had been denied (Nelson, 2007). In 2008 ENI sanctioned the development with an expected spend of \$1.45 billion, with plans at the time to drill 73 wells (Lidji E. , Eni brings North Slope oil field online three years after sanctioning, 2011).



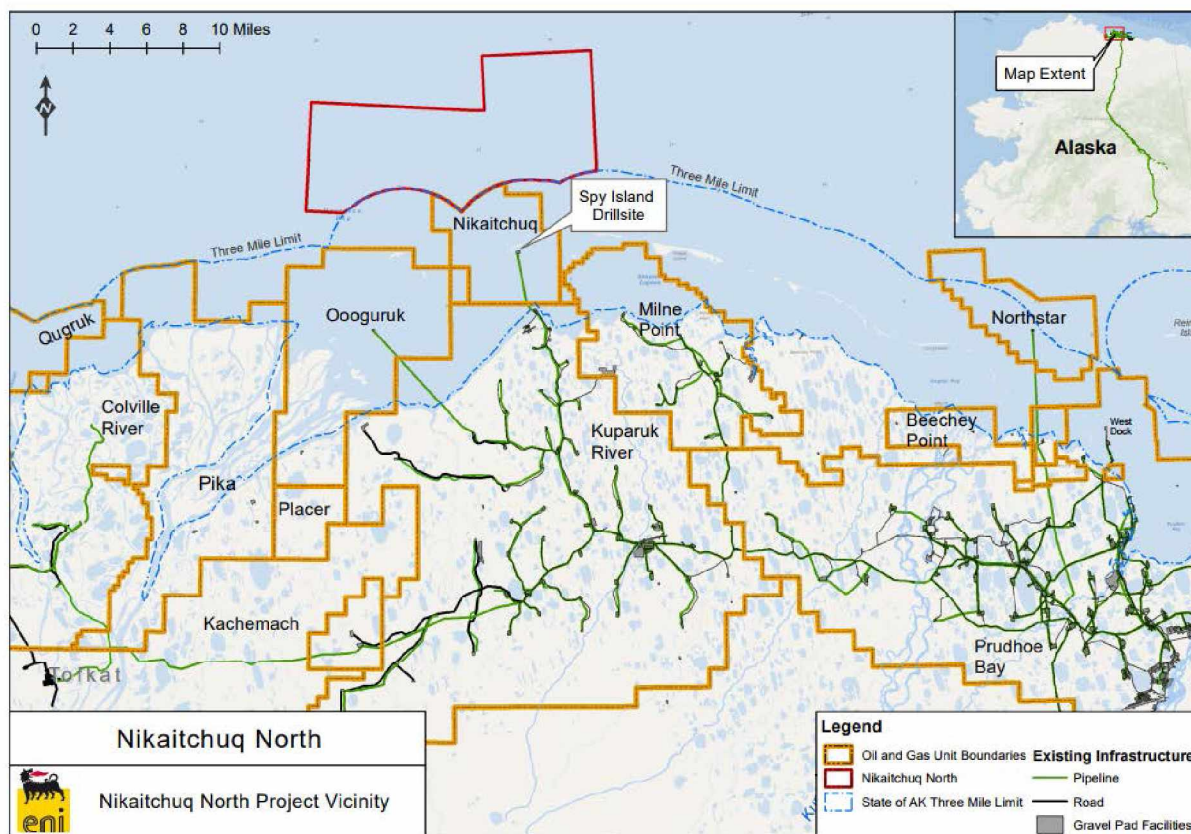


FIGURE 99: NIKAITCHUQ FIELD LOCATION (ENI US OPERATING CO. INC., 2017)

Nikaitchuq produces from the Schrader Bluff reservoir, a formation that is produced in other units at Milne Point, Prudhoe Bay's Orion and Polaris fields, and Kuparuk's West Sak field. It is a low API reservoir, being only 16-18°, and is viscous at 143 cp. It has a gross thickness of 35-50 ft. with a net to gross of 65-93%. It has high porosity is 25-35% (average 29%), and permeabilities of 90-600mD (average 300), Initial water saturation of 26-43% (average 26.5%). It produces from relatively shallow sands 3,000-4,000 feet deep with a reference datum of 3,760 feet. Reservoir temperature is also cool, at 80°F. (AOGCC, 2017) (Abahusayn, Foster, Brink, Kuck, & Longo, 2012).



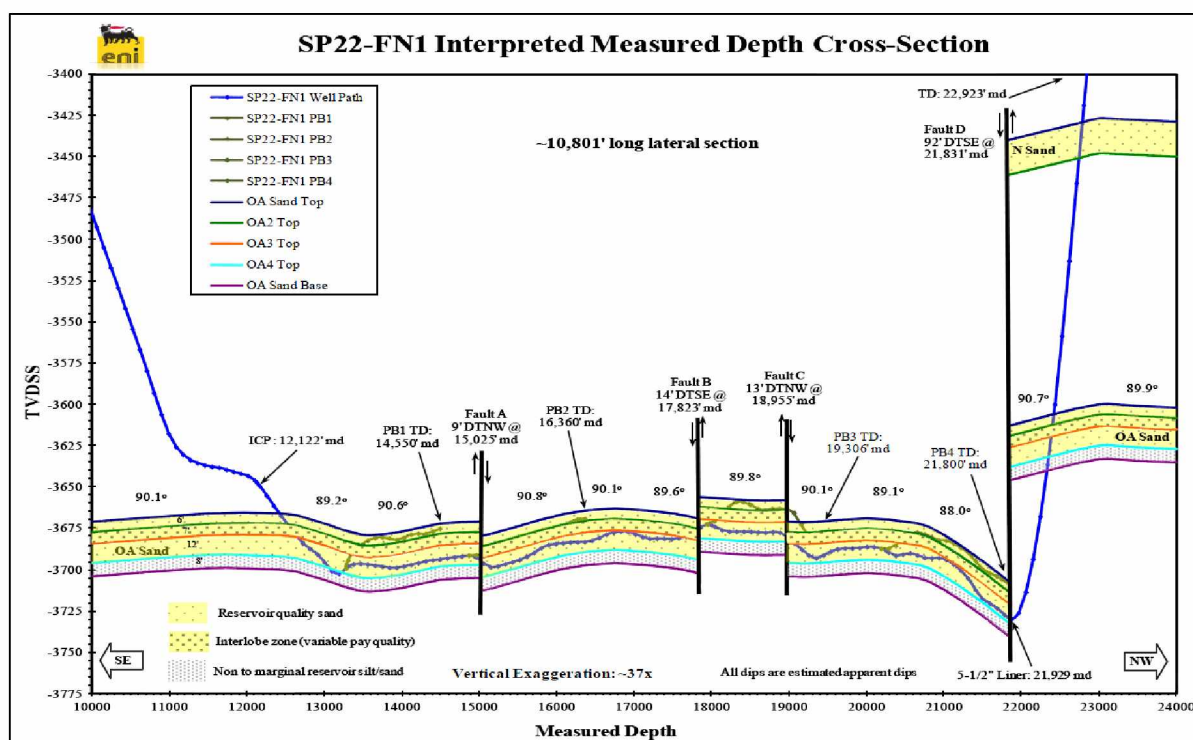


FIGURE 100: NIKATCHUQ SP22-FN1 WELL PATH IN CROSS-SECTION (ENI US OPERATING CO. INC., 2017)

## 12.1. FIELD DEVELOPMENT

To date 51 wells have been permitted in Nikaitchuq, and there are 50 active wells (29 producers, 21 injectors). ENI had plans to drill an ultra-extended reach exploration well from SID in block 6423 in December 2017, and three new wells in 2018, as well as adding new laterals to existing wells. Most wells at Nikaitchuq are considered extended reach wells, and typically comprise of long horizontal wells. To date a million feet of has been drilled (Chaudhry, Sallee, & Burton, 2016). 93% of the wells have a Reach to TVD ratio (ERD Ratio) greater than 4:1, with several of the wells having an ERD ratio greater than 5:1 (Abahusayn, Foster, Brink, Kuck, & Longo, 2012).

TABLE 5: NIKAITCHUQ FIELD WELL COUNT (ENI US OPERATING CO. INC., 2017)

		Reauthorization II (2009)			Western Extension (2014)		East Extension (2015)		Activity up to date (May, 2017)			Dual Lateral Paths	
		OPP	SID	Total	OPP	SID	OPP	SID	OPP	SID	Total	OPP	SID
Well Type	Injector	8/8	11/12	20		2/2		0/1	8/8	13/15	21/23		
	Producer	11/11	15/15	26		2/2		1/2	11/11	18/19	29/30	8/8	9/19
	Disposal	1/1	1/1	2					1/1	1/1	2/2		
	Water Source	3/3	0	3					3/3	0	3/3		
Total		23/23	27/28	51**		4/4		1/3	23/23	32/35	55/58	8/8	9/19

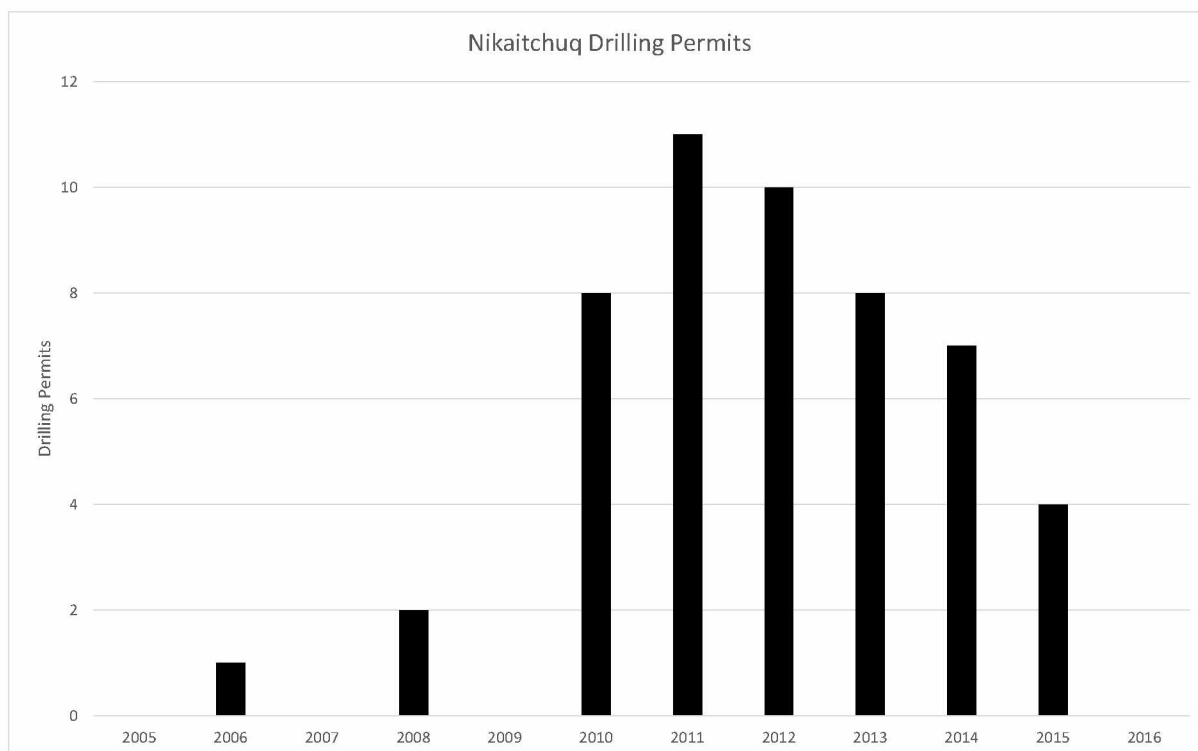


FIGURE 101: NIKAITCHUQ DRILLING PERMITS BY YEAR

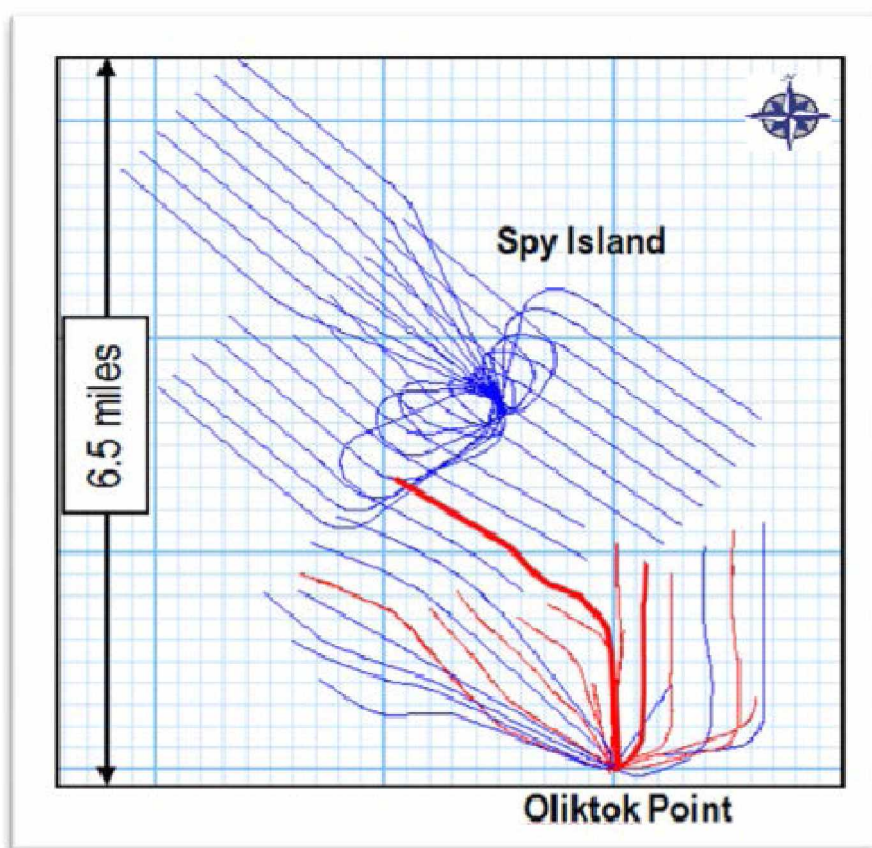


FIGURE 102: PLAN VIEW OF NIKAITCHUQ DEVELOPMENT (ABAHUSAYN, FOSTER, BRINK, KUCK, & LONGO, 2012)

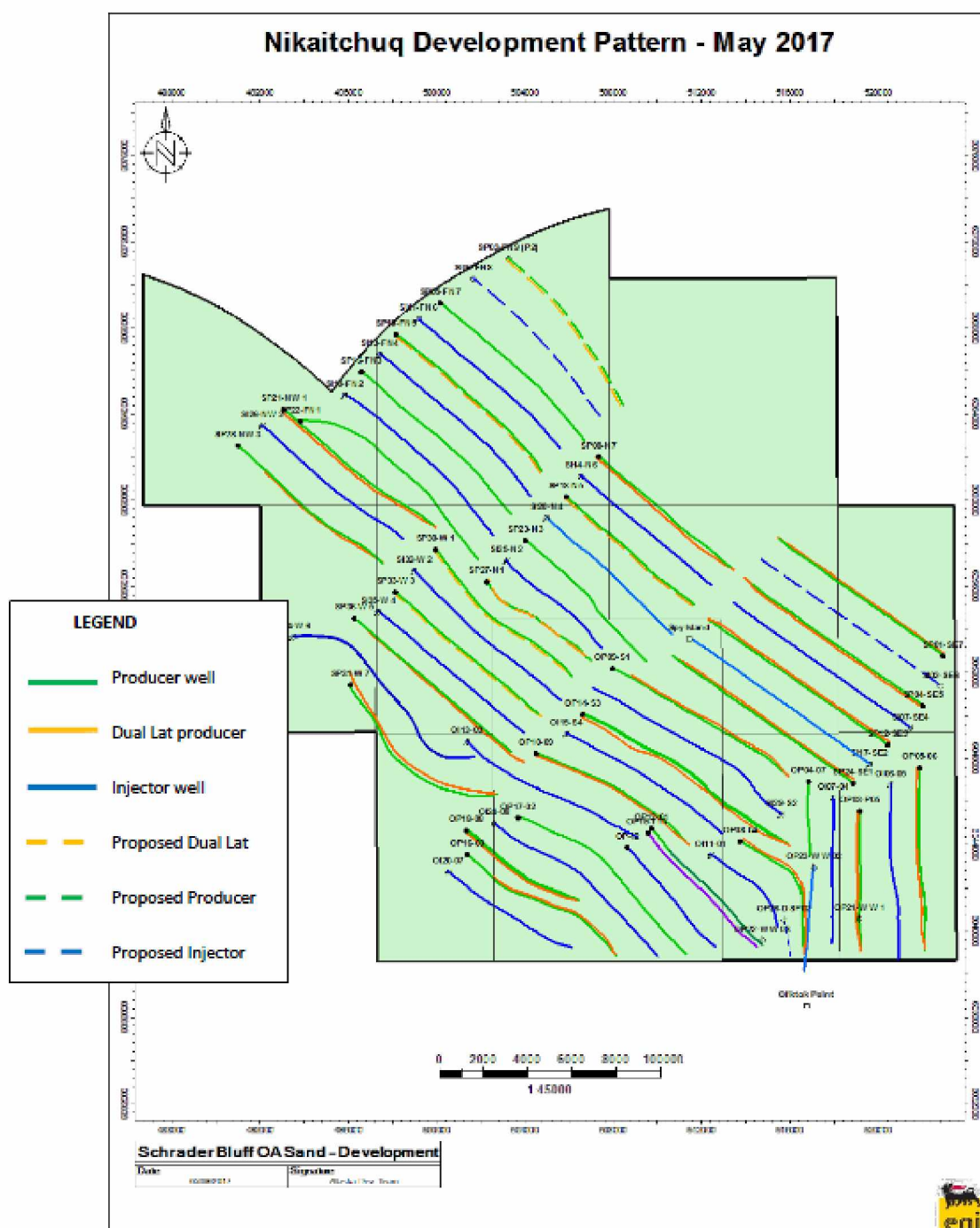


FIGURE 103: PROPOSED NIKAITCHUQ UNIT DEVELOPMENT ACTIVITY MAY 2017 (ENI US OPERATING CO. INC., 2017)

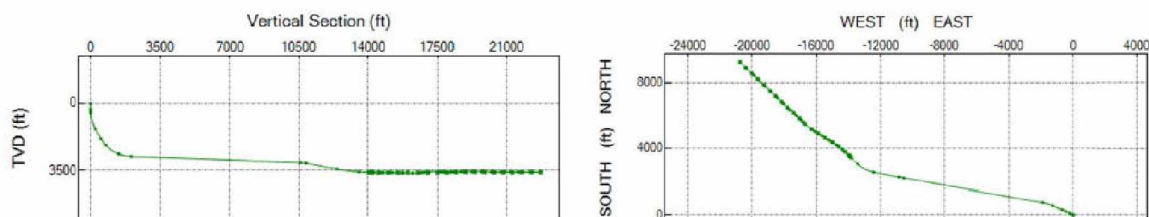


FIGURE 104: TYPICAL NIKAITCHUQ ERD WELL PATH (CHAUDHRY, SALLEE, &amp; BURTON, 2016)



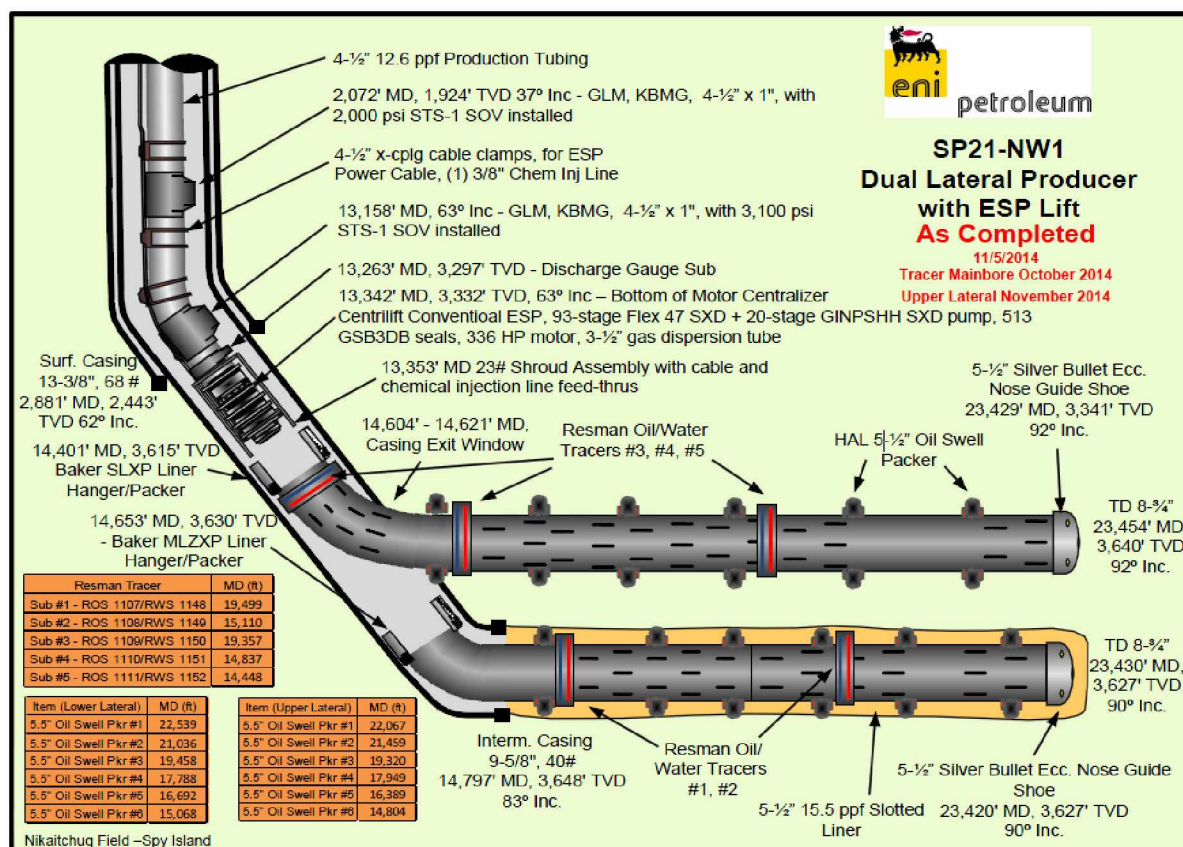


FIGURE 105: NIKAITCHUQ DUAL LATERAL WELL SCHEMATIC (ENI US OPERATING CO. INC., 2017)

Nikaichuq has a dedicated processing plant that can handle up to 40,000 bopd of oil and 120,000 bwpd (Lidji E. , Eni brings North Slope oil field online three years after sanctioning, 2011). Production came online in January 2011 exceeded reached plateau rate of approximately 25,000 bopd in September 2014, peaking at 25,940 bopd in November 2015. Average production rates for the first half of 2017 is approximately 21,000 bopd. The field has recovered 40 MMBO to date and has a producing watercut of 53%, and producing GOR of 140 scf/bbl.

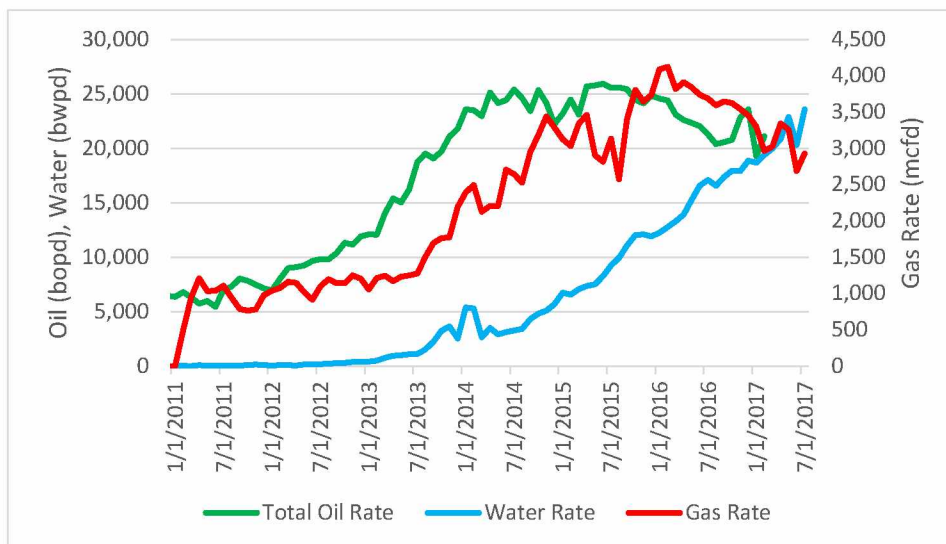


FIGURE 106: NIKAITCHUQ PRODUCTION

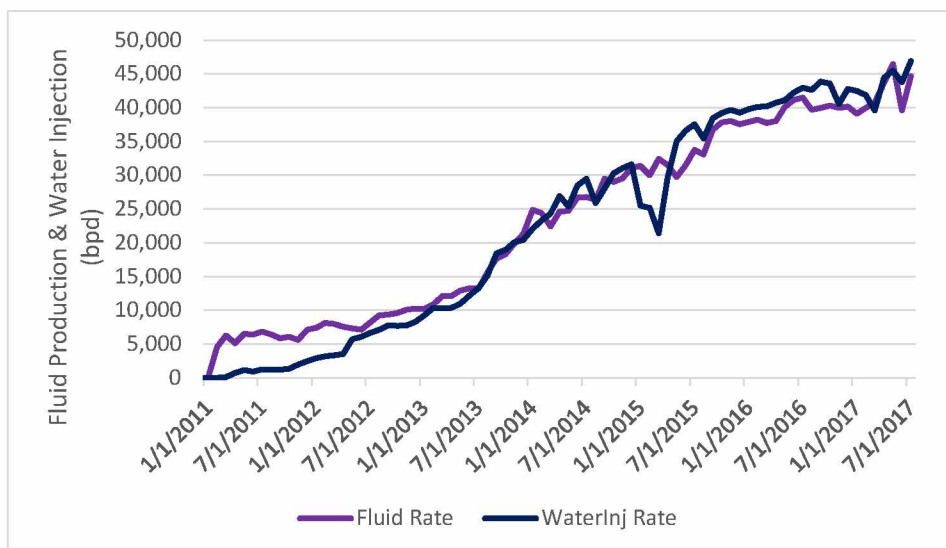


FIGURE 107: NIKAITCHUQ FLUID PRODUCTION AND WATER INJECTION

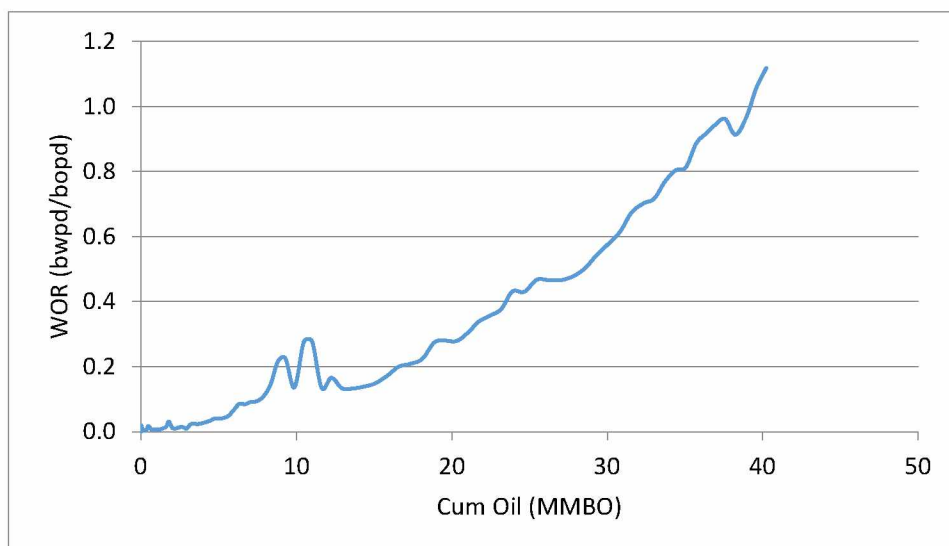


FIGURE 108: NIKAITCHUQ WATER OIL RATIO VS CUM OIL

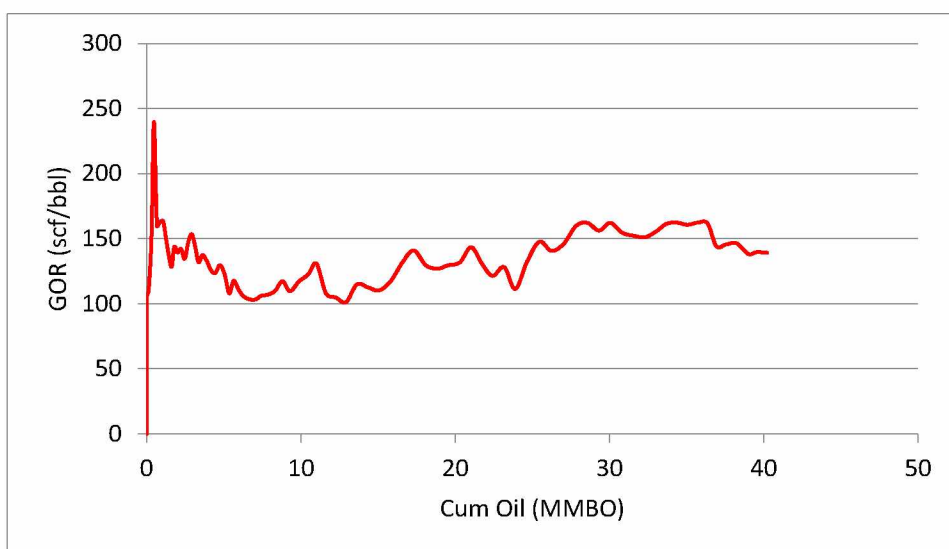


FIGURE 109: NIKAITCHUQ GAS OIL RATIO VS. CUM OIL

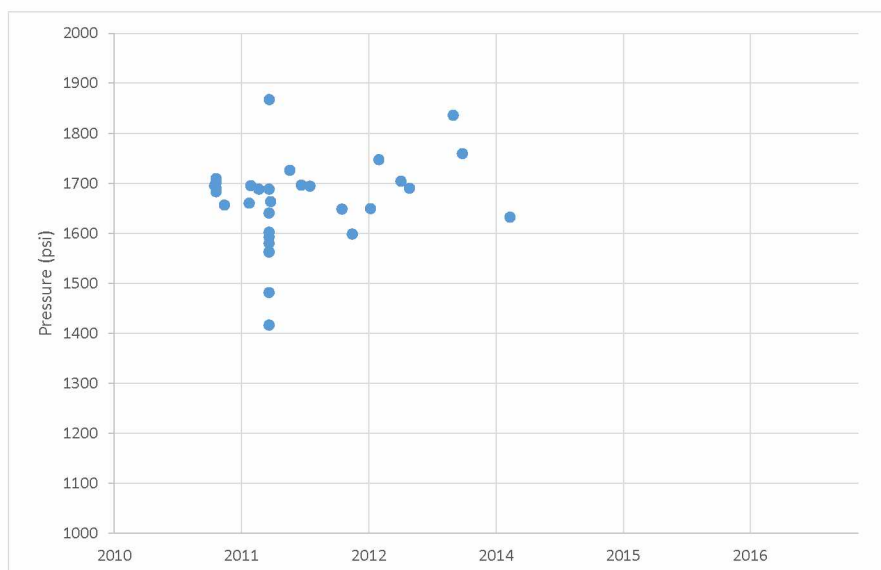


FIGURE 110: NIKAITCHUQ REPORTED PRESSURES

It is premature to give long-term forecast to Nikaitchuq since there is not a long history of decline. Also, declines after plateau are typically steeper than the long term hyperbolic decline that follows water breakthrough. Recent decline may also be affected by operational considerations. If recent decline is used to forecast future field performance, then Nikaitchuq will recover less than half of the expected 220 MMBO recoverable volume predicted in 2011 (Lidji E. , Eni brings North Slope oil field online three years after sanctioning, 2011). The 90-100 MMBO recoverable forecast is close to the bottom of the range of the original recovery estimate of 120-200 MMBO stated in the pool rules, and additional development, development in the N sand, or improvement in decline may push it into this range (AOGCC, 2011).

TABLE 6: NIKAITCHUQ HYDROCARBON RECOVERY (AOGCC, 2011)

Hydrocarbon Recovery	(MMSTB)
Original Oil-in-Place (OOIP) – OA Sand	800 - 930
Primary Recovery (4 – 5 % OOIP)	30 - 45
Primary + Water flood (a total of 15% to 22% of OOIP)	120 - 200

### 13. NORTHSTAR

The Northstar unit is operated by Hilcorp and consists of two pools, the Northstar field which produces from the Ivishak, and the more recently developed shallower pool Northstar Kuparuk.



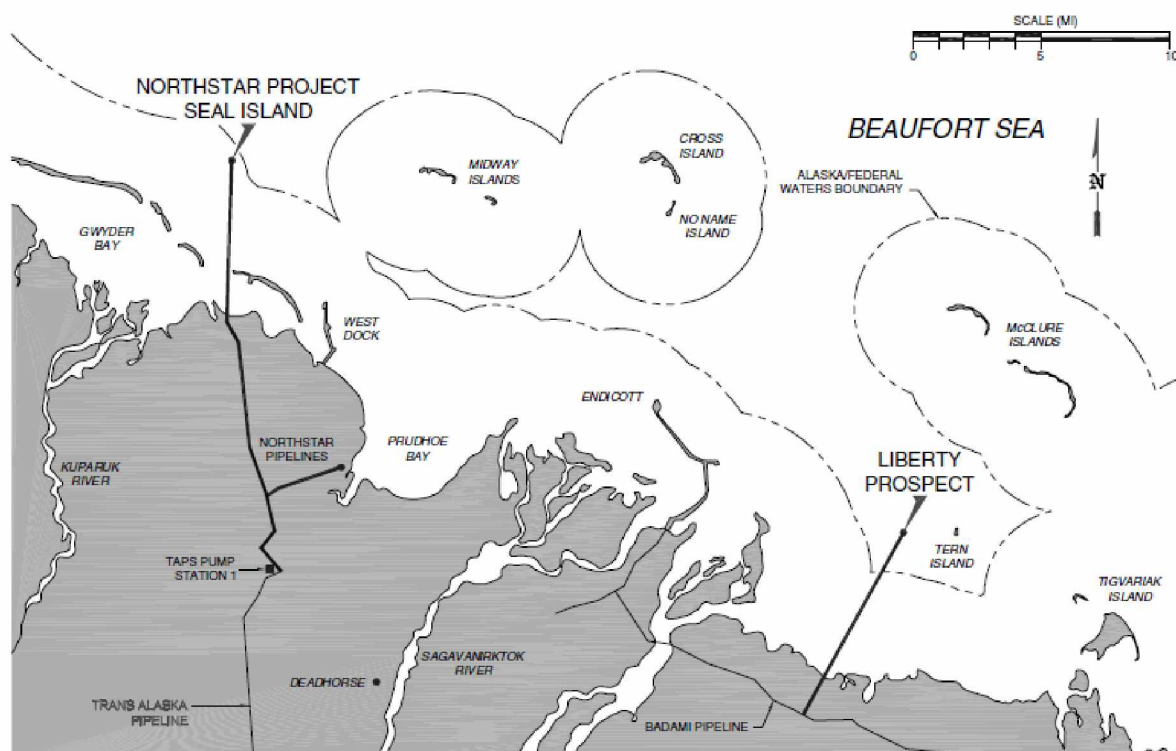


FIGURE 111: NORTHSTAR PROJECT MAP (LANAN, ENNIS, EGGER, & YOCKEY, 2001)

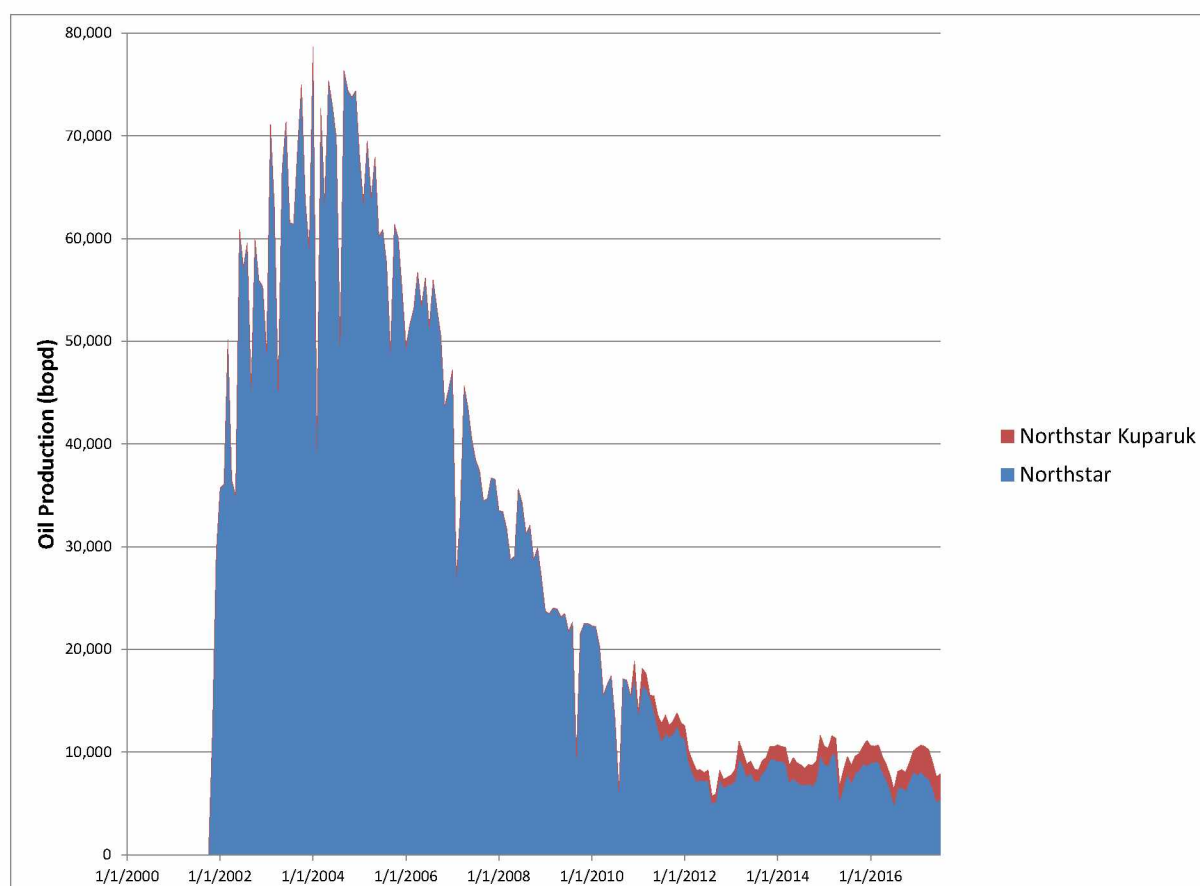


FIGURE 112: NORTHSTAR UNIT PRODUCTION

### 13.1. NORTHSTAR

The Northstar field is produced from a man-made gravel island in 37 feet of water in the Beaufort Sea. It is 6 miles offshore, and is the first offshore field in the arctic to use a subsea pipeline (Lanan, Ennis, Egger, & Yockey, 2001). It was discovered in 1983 by Shell, and developed by BP with first oil occurring in 2001. Production peaked around 75,000 bopd and the field has produced 167 million barrels of oil. The field is currently producing 4,000 bopd from 22 active wells.

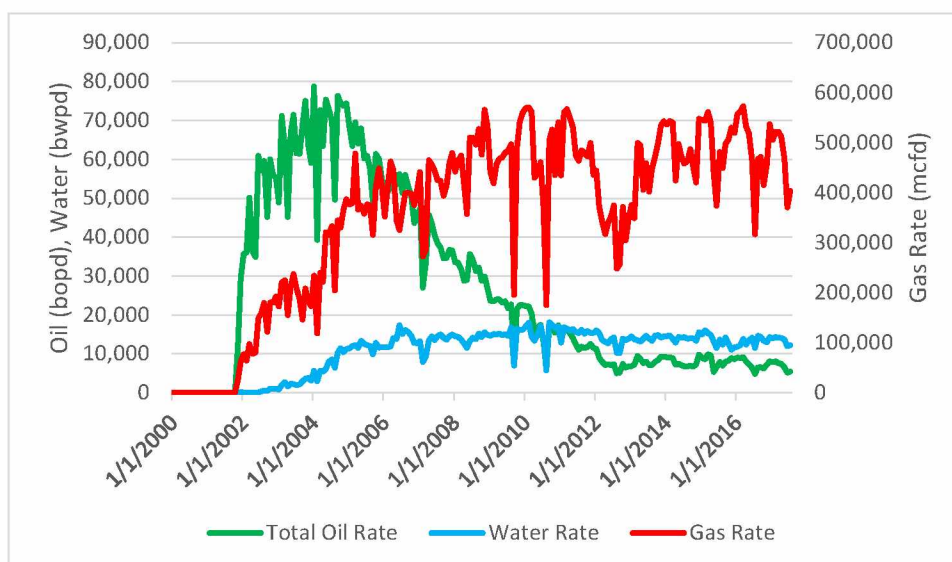


FIGURE 113: NORTHSTAR FIELD PRODUCTION



FIGURE 114: NORTHSTAR PRODUCTION AND ACTIVE WELLS

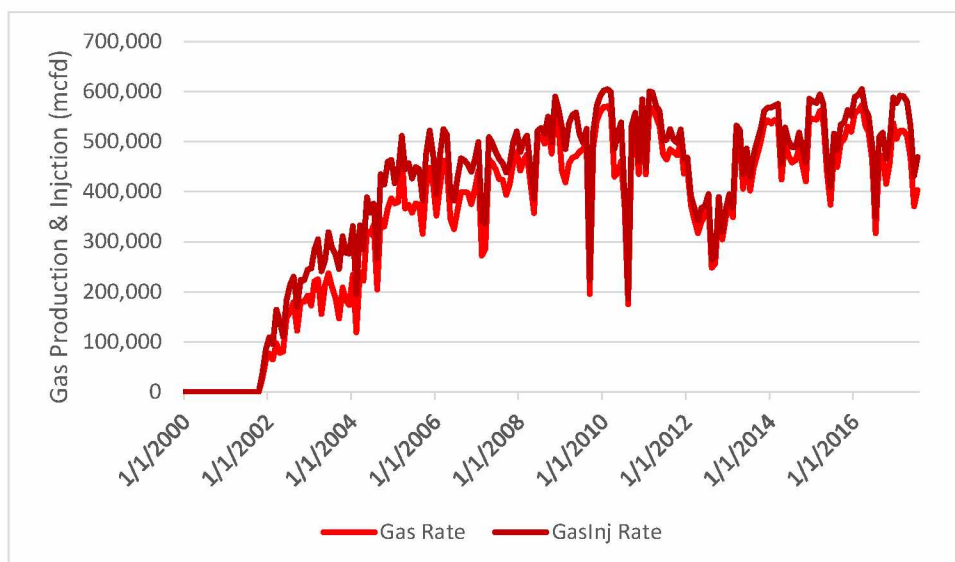


FIGURE 115: NORTHSTAR GAS AND INJECTION RATES

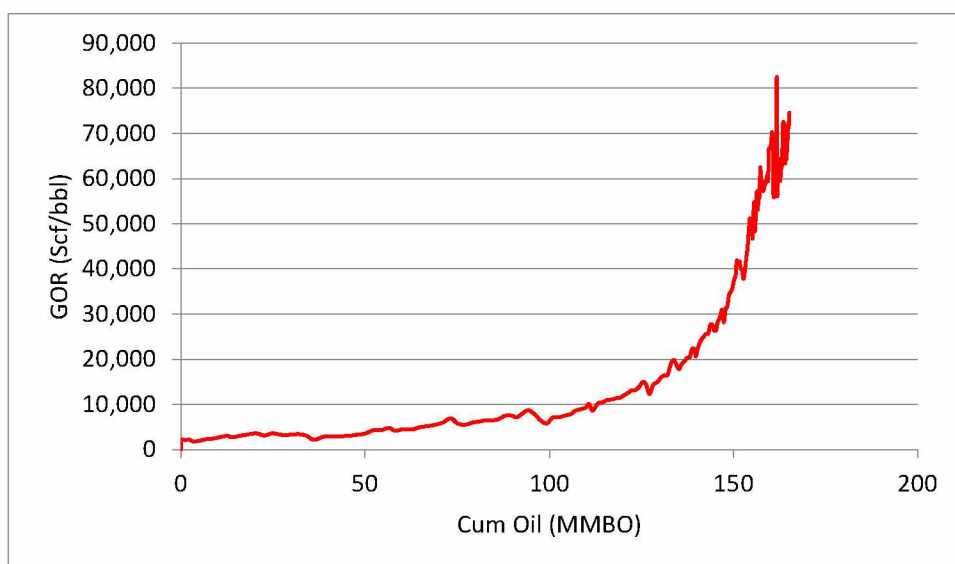


FIGURE 116: NORTHSTAR GAS OIL RATIO VS. CUM OIL

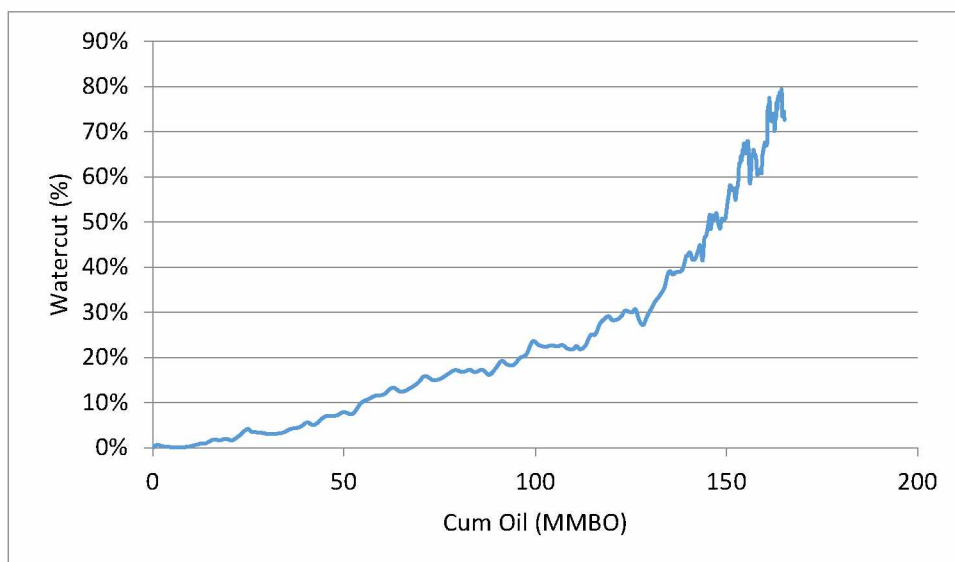


FIGURE 117: NORTHSTAR WATERCUT VS. CUM OIL

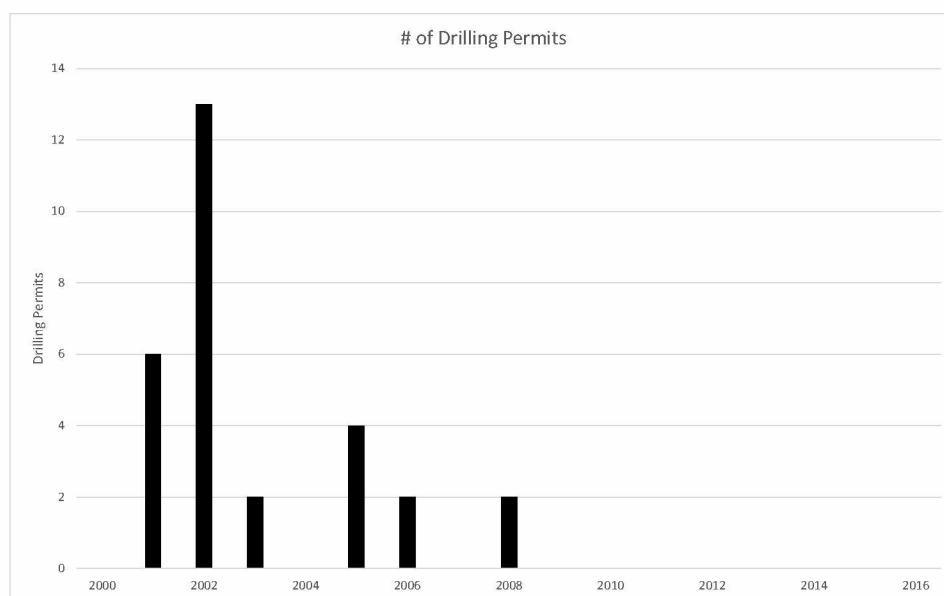


FIGURE 118: NORTHSTAR DRILLING PERMITS BY YEAR

### 13.2. NORTHSTAR KUPARUK

The Northstar Kuparuk pool began in 2010, nine years after field development. It consists of two active wells which combined have produced 3.1 million barrels of oil and are currently producing 2,500 bopd.

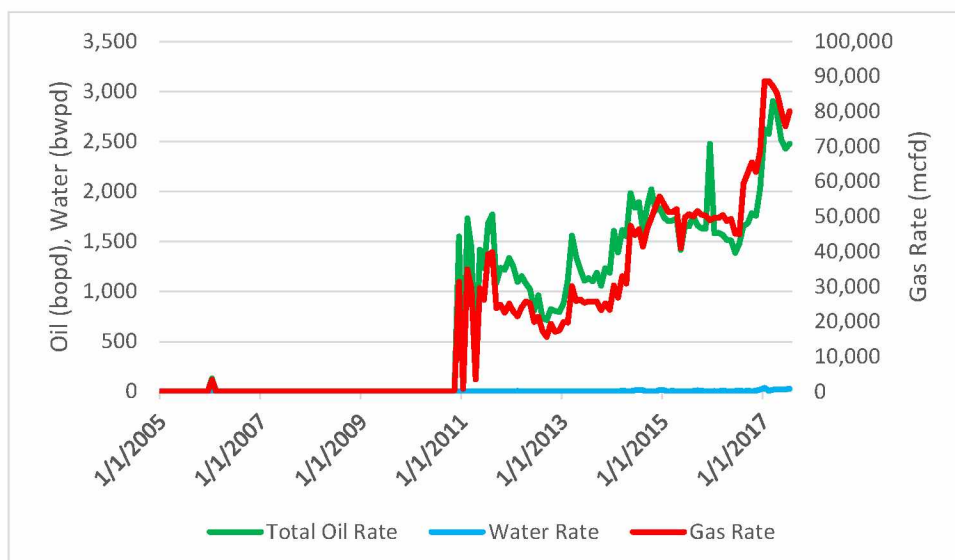


FIGURE 119: NORTHSTAR KUPARUK FIELD PRODUCTION

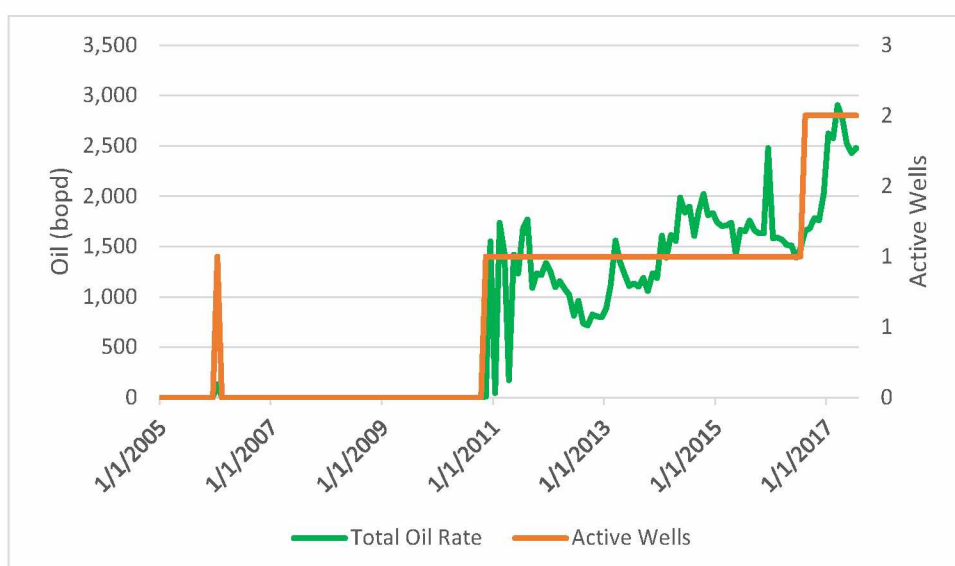


FIGURE 120: NORTHSTAR KUPARUK PRODUCTION AND ACTIVE WELLS

## 14. OOGURUK

The Oooguruk Unit comprises of three fields: the Oooguruk Nuiqsut, the Oooguruk Kuparuk, and the Oooguruk Torok. Caelus operates the field and holds a 70% working interest, while ENI holds 30%. There are 43 wells in the unit, 28 in the Nuiqsut field, five in the Kuparuk, and four in the Torok. There is also a disposal well and five other exploration and appraisal wells outside the existing participating areas (Caelus Natrual Resources Alaska, LLC, 2017). The field produces to facilities in the Kuparuk River Unit, and have an estimated 6% back-out associated with its production (Department of Natural Resources, 2015).





FIGURE 121: OOGURUK LOCATION MAP (CAELUS NATURAL RESOURCES ALASKA, LLC, 2017)

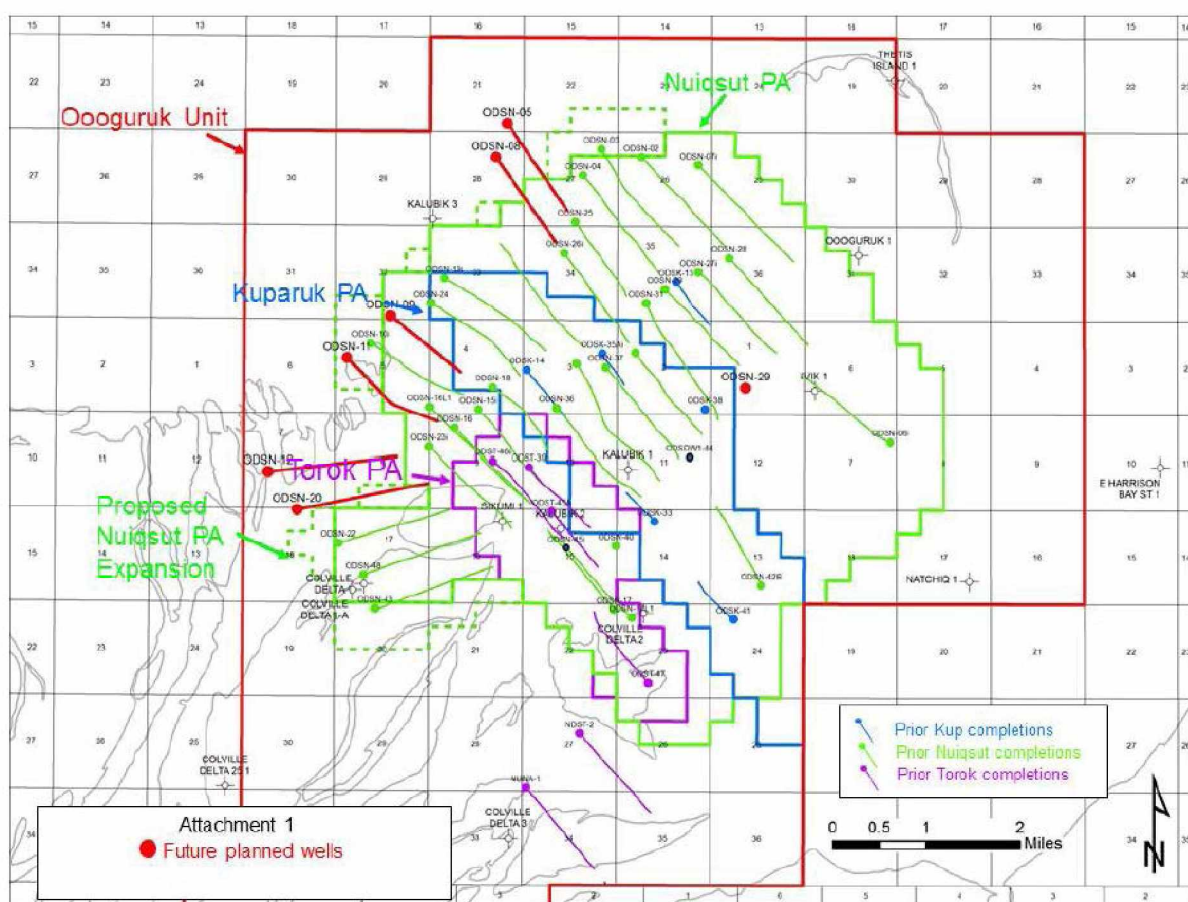


FIGURE 122: OOGURUK UNIT MAP (CAELUS NATURAL RESOURCES ALASKA, LLC, 2017)

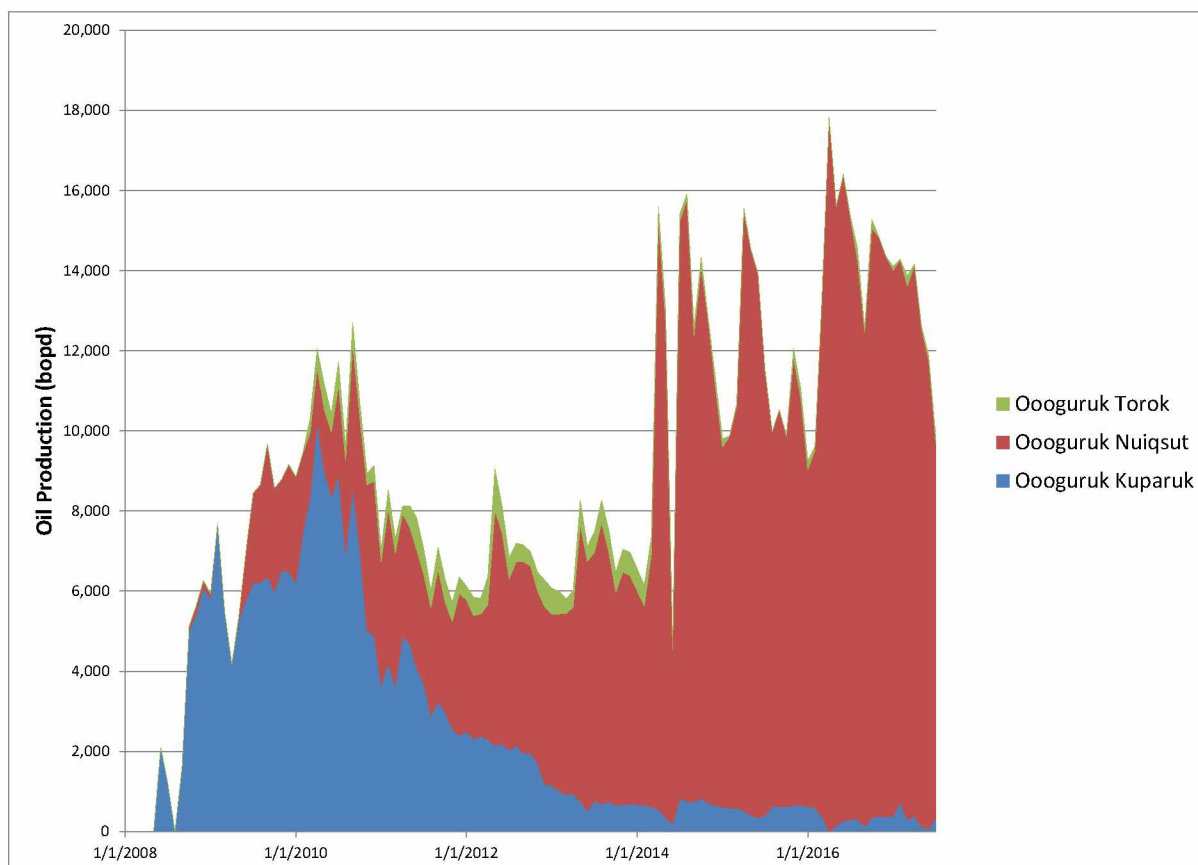


FIGURE 123: OOOGURUK PRODUCTION

#### 14.1. OOOGURUK KUPARUK

The Oooguruk Kuparuk was the first developed pool of the Oooguruk development and began production in 2008, and peaked at 10,000 bopd. The field has produced 8.5 million barrels of oil, which is the high side of the original development expectations for the pool. The field currently produces 300 bopd from three wells.

TABLE 7: OOOGURUK KUPARUK OIL IN PLACE AND EXPECTED RECOVERY (AOGCC, 2012)

Hydrocarbon Volume	Low Estimate (MMSTB)	High Estimate (MMSTB)
Original Oil in Place (OOIP)	15	25
Primary Recovery (6% to 10% of OOIP)	1	2.5
Primary + Waterflood (26 to 34% of OOIP)	4	8.5



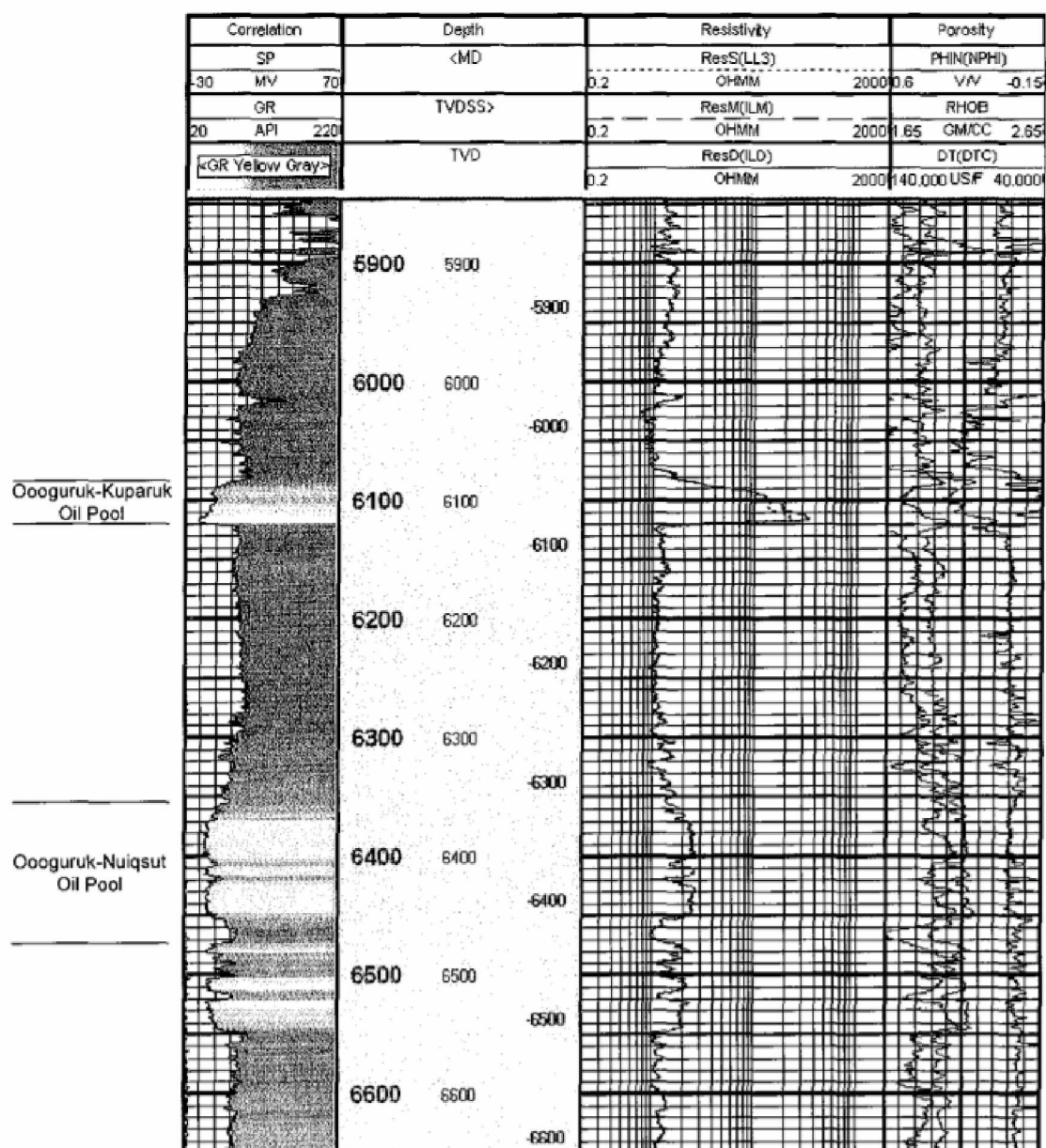


FIGURE 124: OOGURUK KUPARUK &amp; NUIQSUT TYPE LOG (AOGCC, 2012)

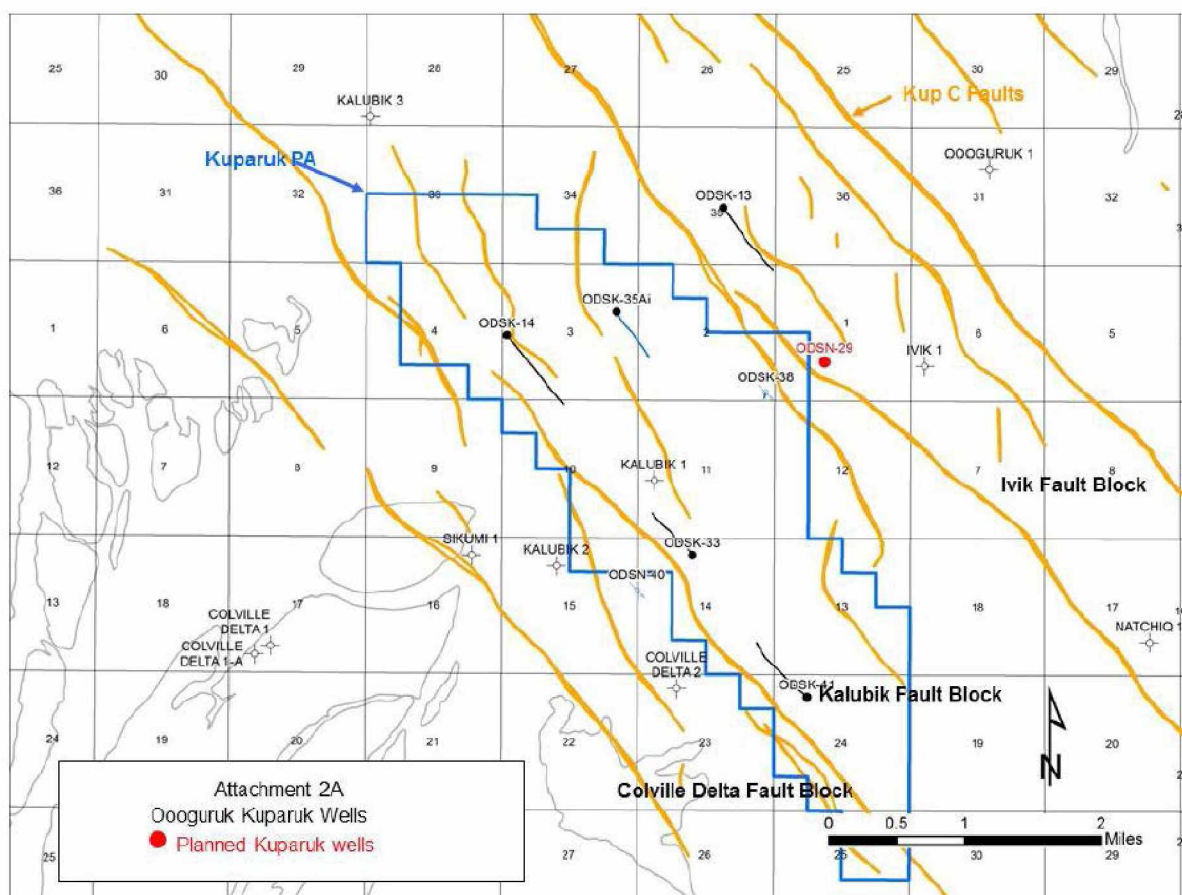


FIGURE 125: OOOGURUK KUPARUK MAP (CAELUS NATURAL RESOURCES ALASKA, LLC, 2017)

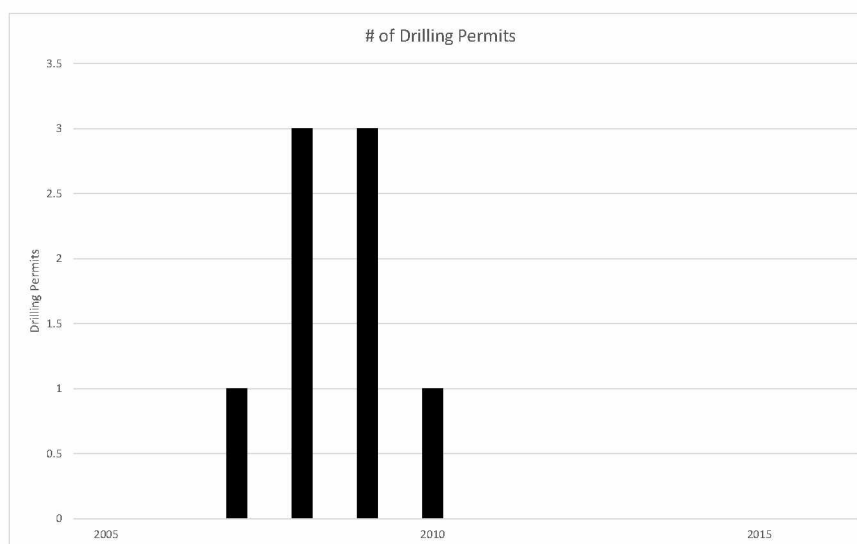


FIGURE 126: OOOGURUK KUPARUK DRILLING PERMITS BY YEAR

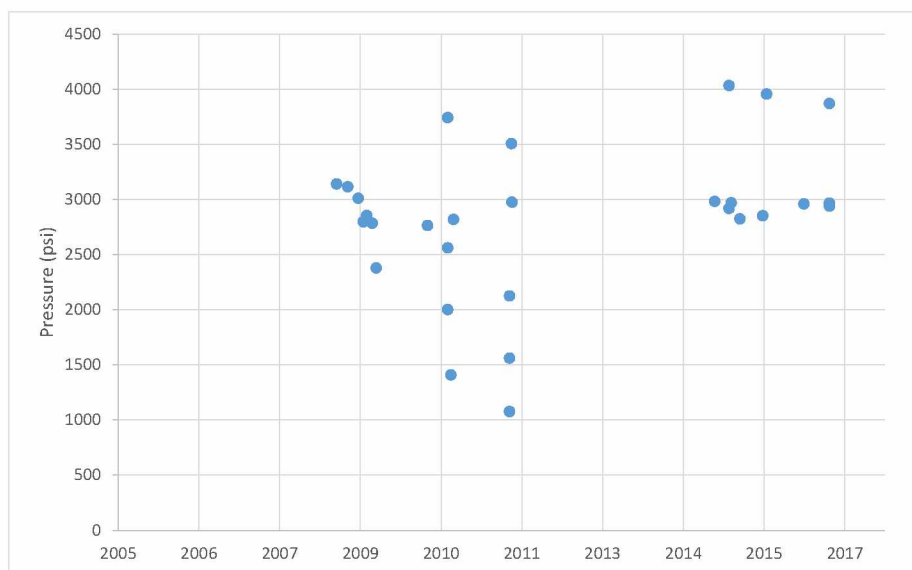


FIGURE 127: OOGURUK KUPARUK PRESSURE

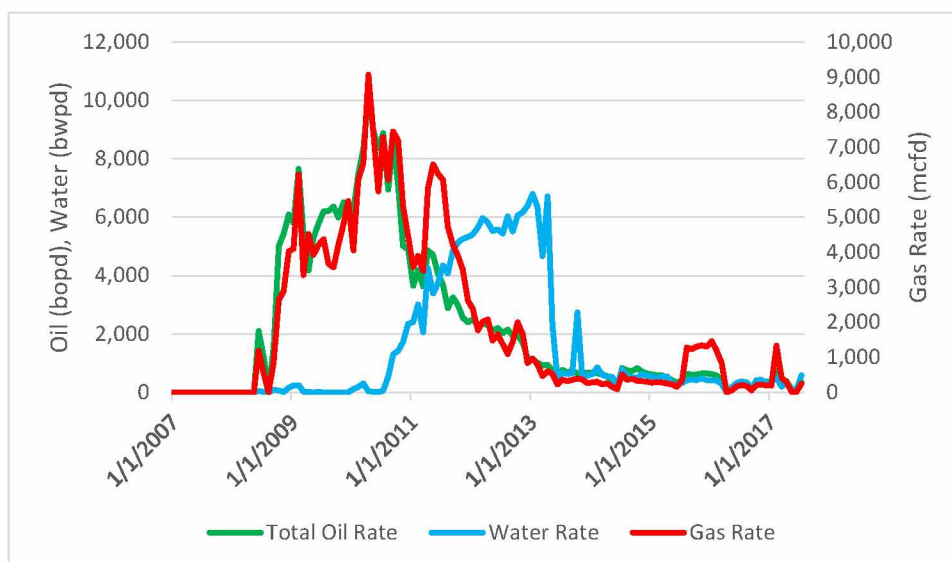


FIGURE 128: OOGURUK KUPARUK PRODUCTION

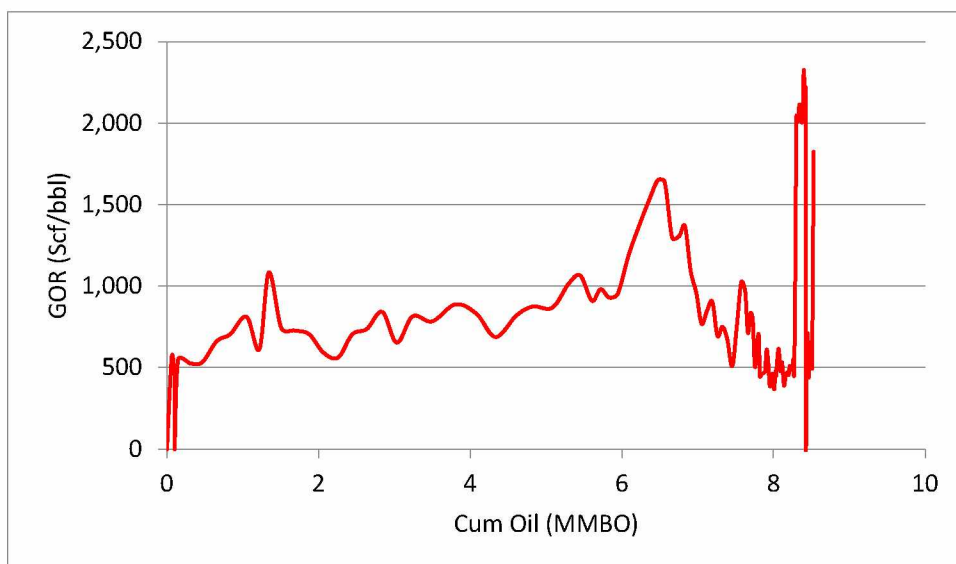


FIGURE 129: OOOGURUK KUPARUK GAS OIL RATIO VS CUM OIL

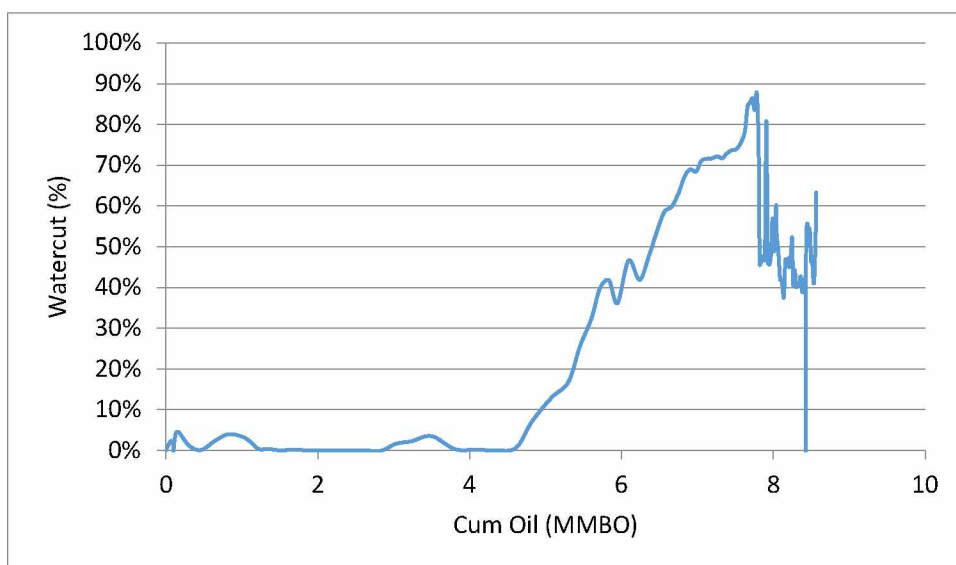


FIGURE 130: OOOGURUK KUPARUK WATERCUT VS. CUM OIL

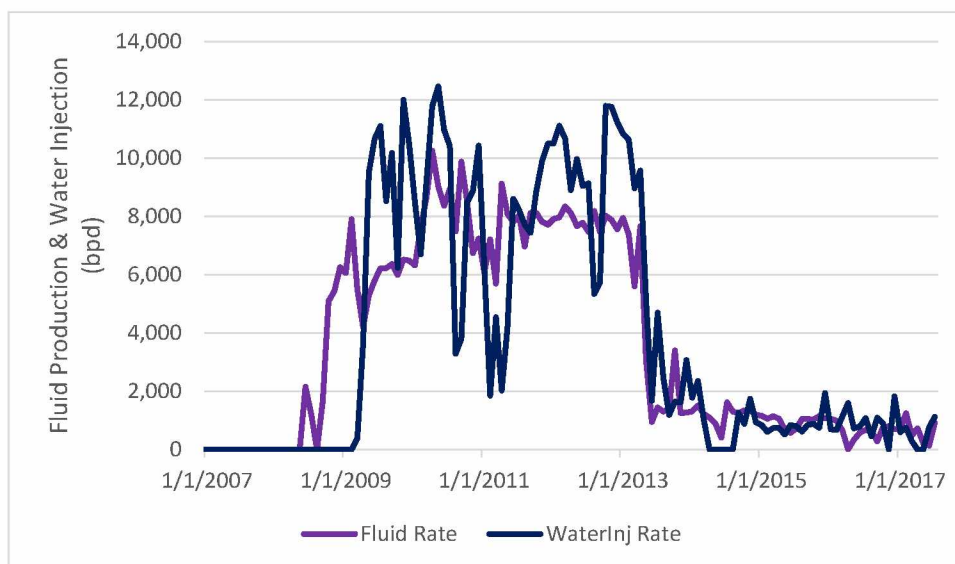


FIGURE 131: OOOGURUK KUPARUK FLUID PRODUCTION AND WATER INJECTION RATE

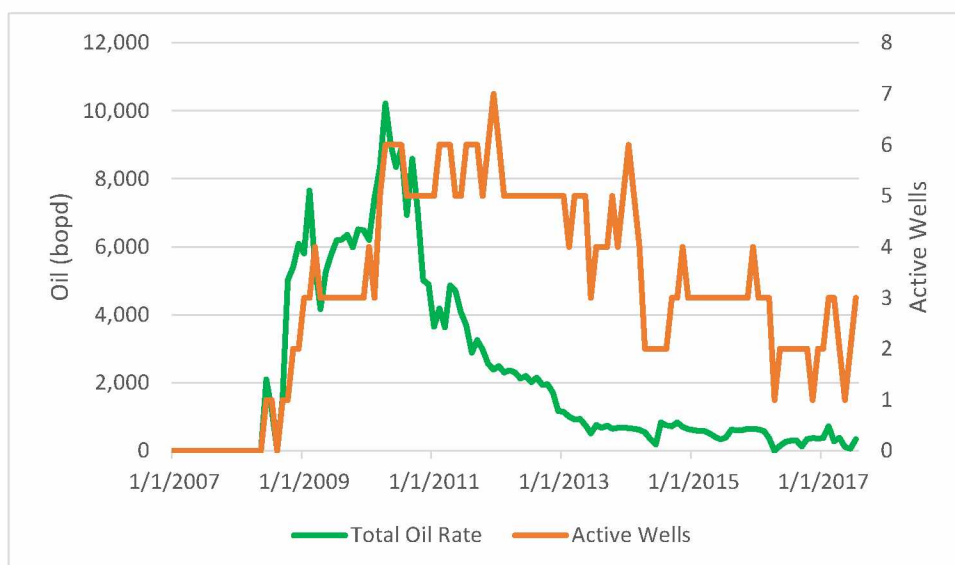


FIGURE 132: OOOGURUK KUPARUK OIL RATE AND ACTIVE WELLS

## 14.2. OOOGURUK NUIQSUT

The Oooguruk Nuiqsut pool began production in 2008 and produced at rates over 17,000 barrels of oil per day and is continuing to ramp up production. It has produced 19 million barrels of oil and averaged four new wells a year from 2012-2015 and is producing from 25 active wells.

FIGURE 133: OOGURUK NUIQSUT MAP (CAELUS NATRUAL RESOURCES ALASKA, LLC, 2017)



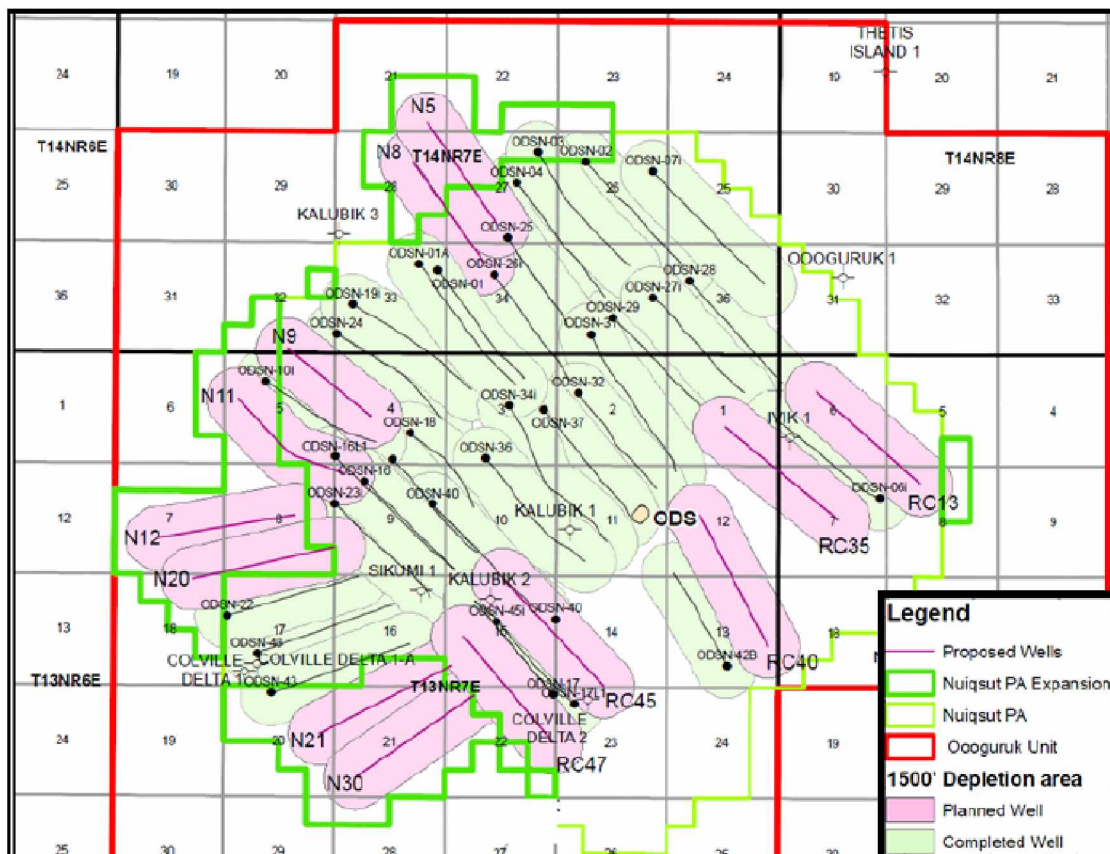


FIGURE 134: OOOGURUK NUIQSUT MAP WITH PLANNED WELLS (CAELUS NATURAL RESOURCES ALASKA, LLC, 2017)

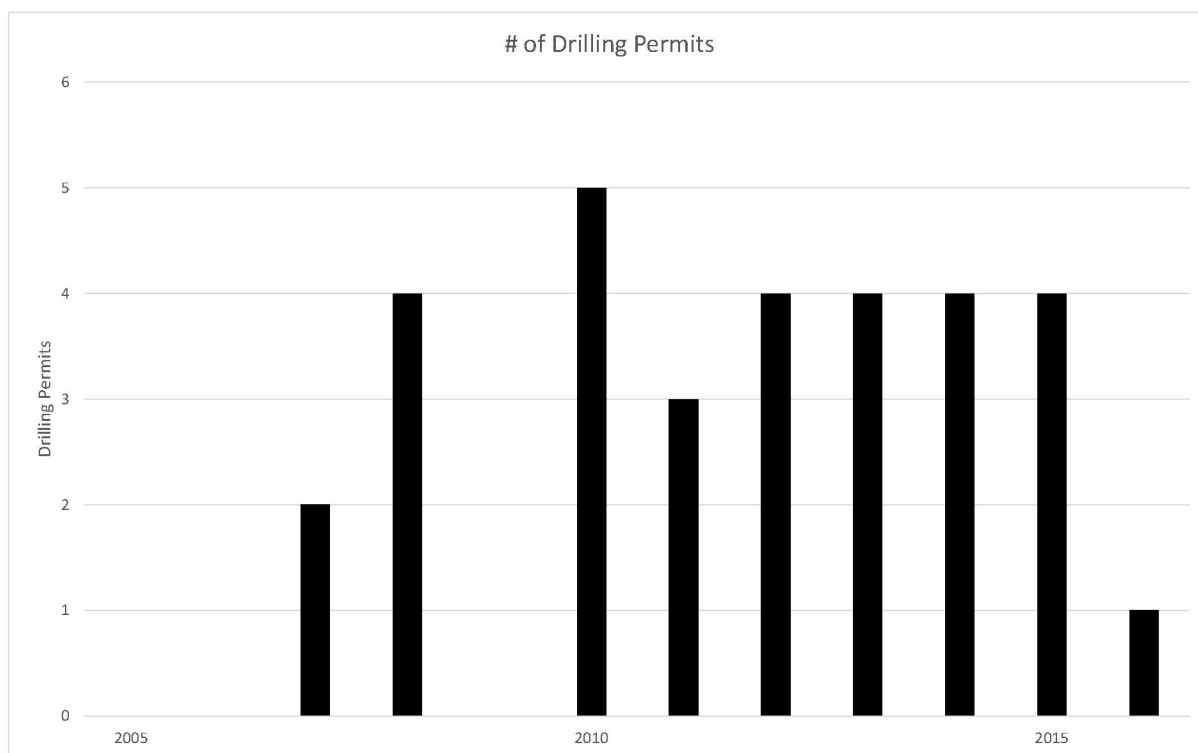


FIGURE 135: OOOGURUK NUIQSUT DRILLING PERMITS BY YEAR



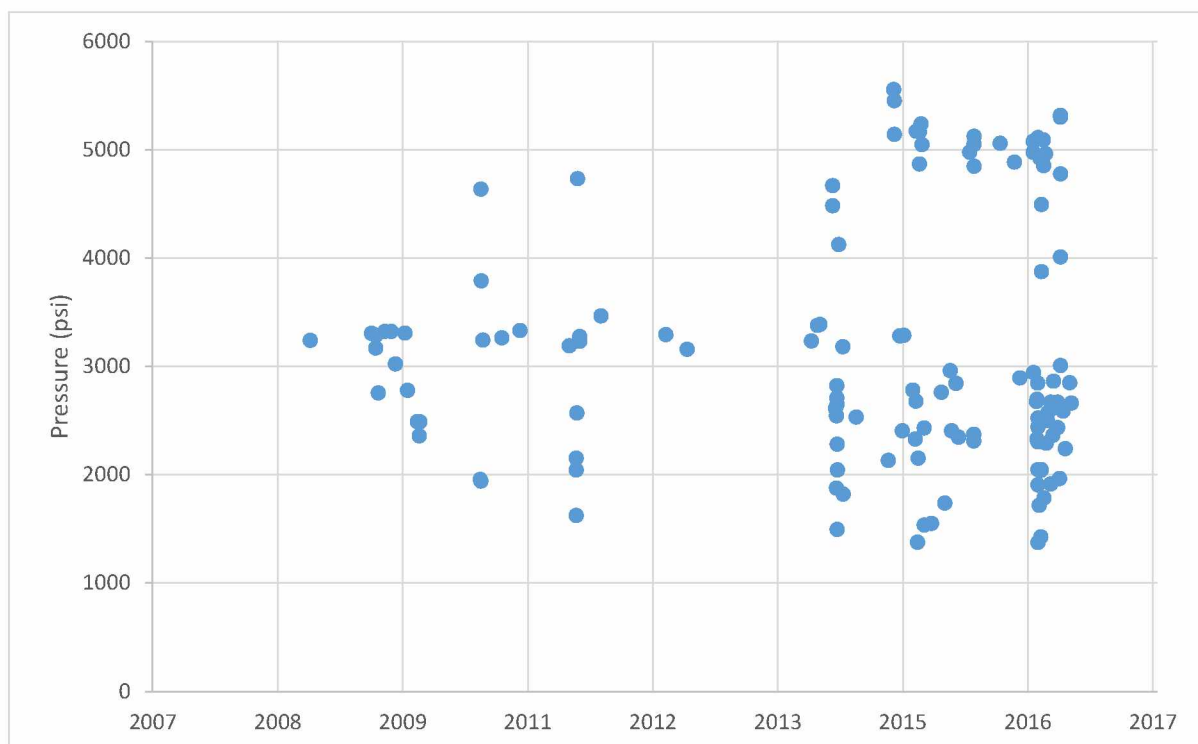


FIGURE 136: OOOGURUK NUIQSUT PRESSURES

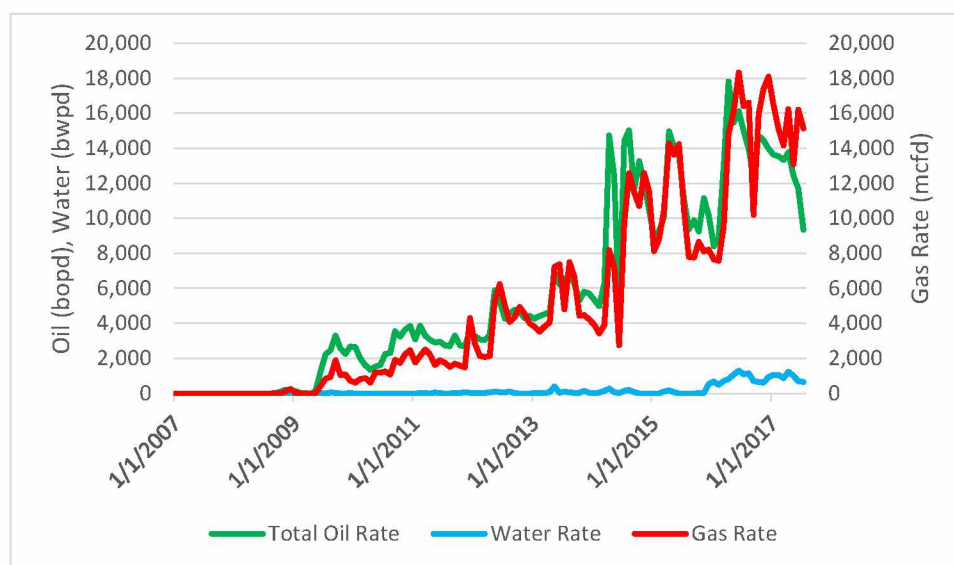


FIGURE 137: OOOGURUK NUIQSUT PRODUCTION

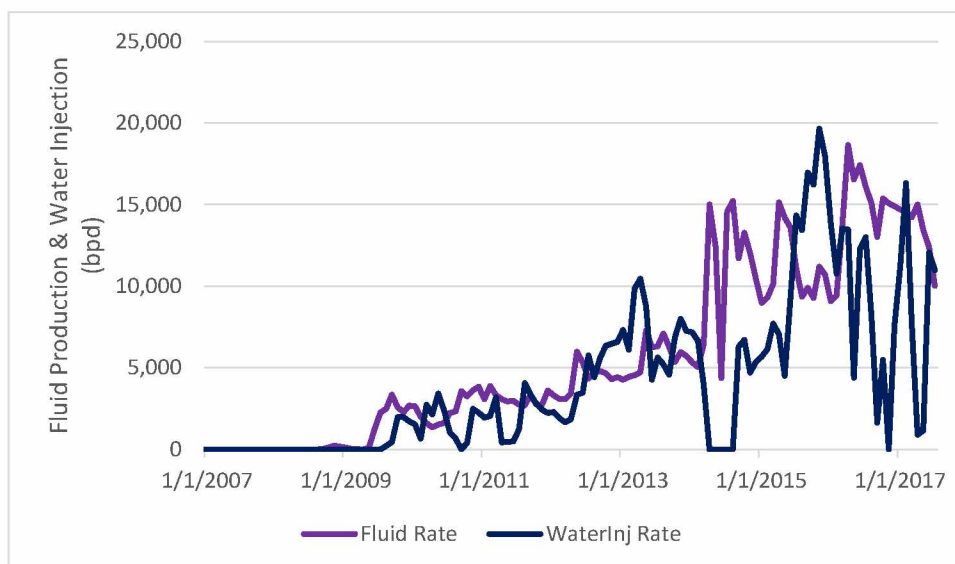


FIGURE 138: OOOGURUK NUIQSUT FLUID PRODUCTION AND WATER INJECTION RATE

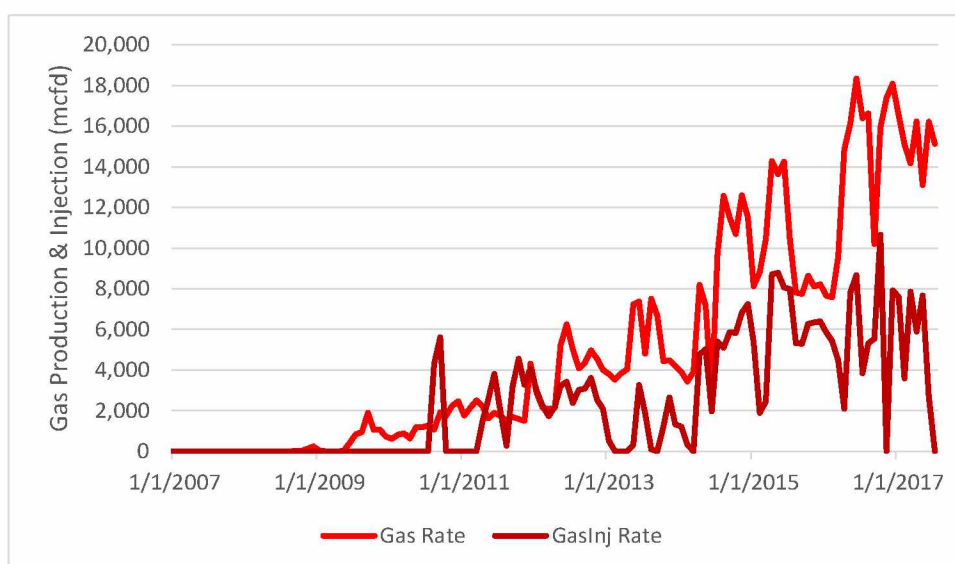


FIGURE 139: OOOGURUK NUIQSUT GAS PRODUCTION AND INJECTION

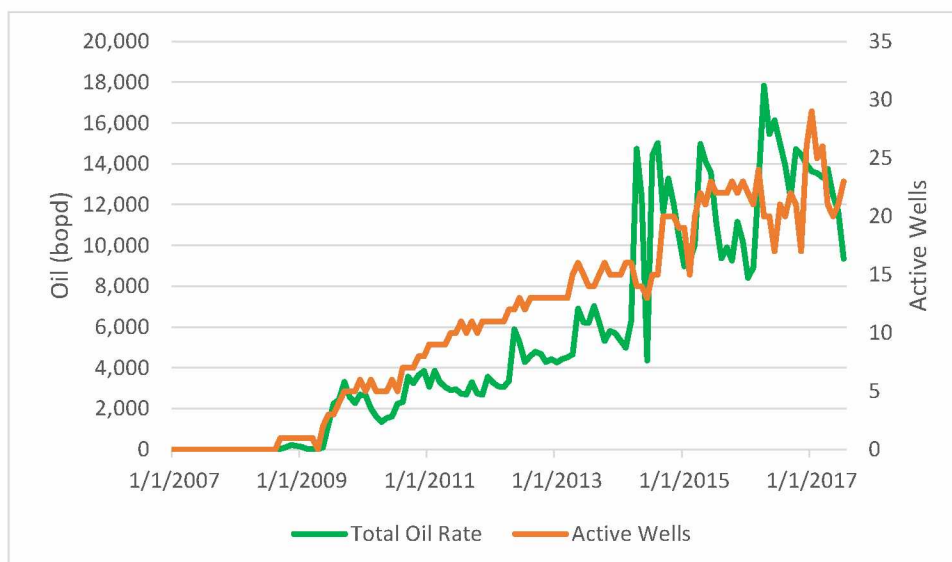


FIGURE 140: OOGURUK NUIQSUT PRODUCTION AND ACTIVE WELLS

### 14.3. OOGURUK TOROK

The Oooguruk Torok field began production in 2010 and has produced 0.8 million barrels. There are four wells in the development, two of which are currently active, producing about 200 bopd.

TABLE 9: OOGURUK TOROK OIL IN PLACE AND EXPECTED RECOVERY (AOGCC, 2012)

Development Phase	OOIP	Primary Recovery (5% of OOIP)	Incremental IWAG Recovery (Low/Median/High – 5%/15 %/25% of OOIP)	Combined Recovery (Low/Median/High – 10%/20%/30% of OOIP)
ODS	50	2.5	2.5/7.5/12.5	5/10/15
Onshore Core Area	290	14.5	14.5/43.5/72.5	29/58/87
Onshore Expansion Area	350	17.5	17.5/52.5/87.5	35/70/105
OTOP Total	690	34.5	34.5/103.5/172.5	69/138/207

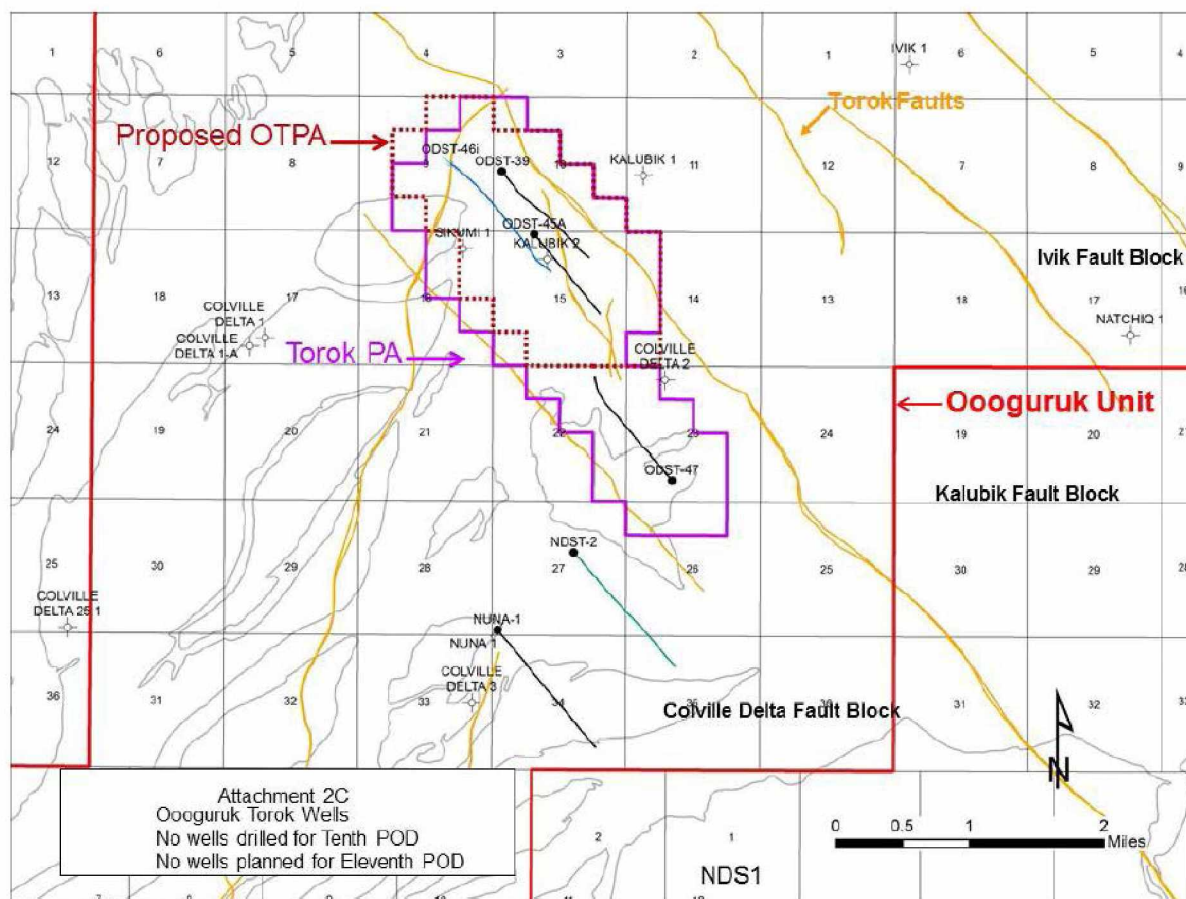


FIGURE 141: OOOGURUK TOROK MAP (CAELUS NATURAL RESOURCES ALASKA, LLC, 2017)

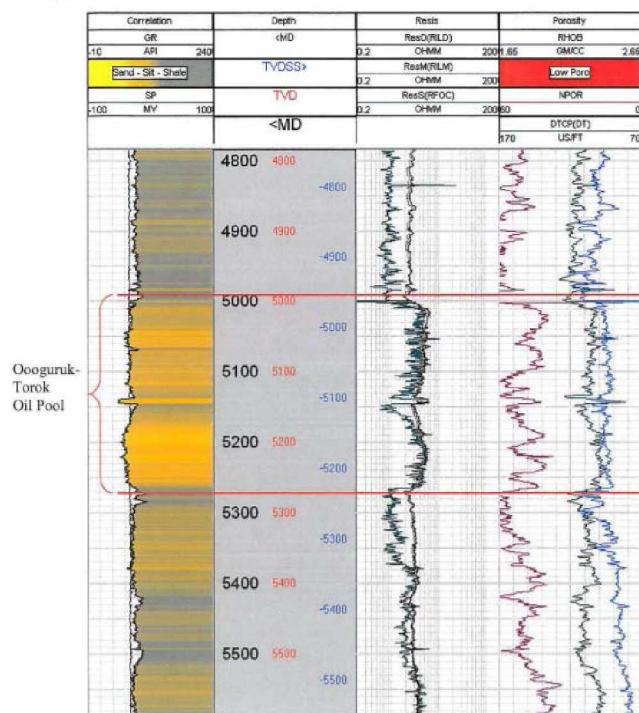


FIGURE 142: OOOGURUK TOROK TYPE LOG (AOGCC, 2012)

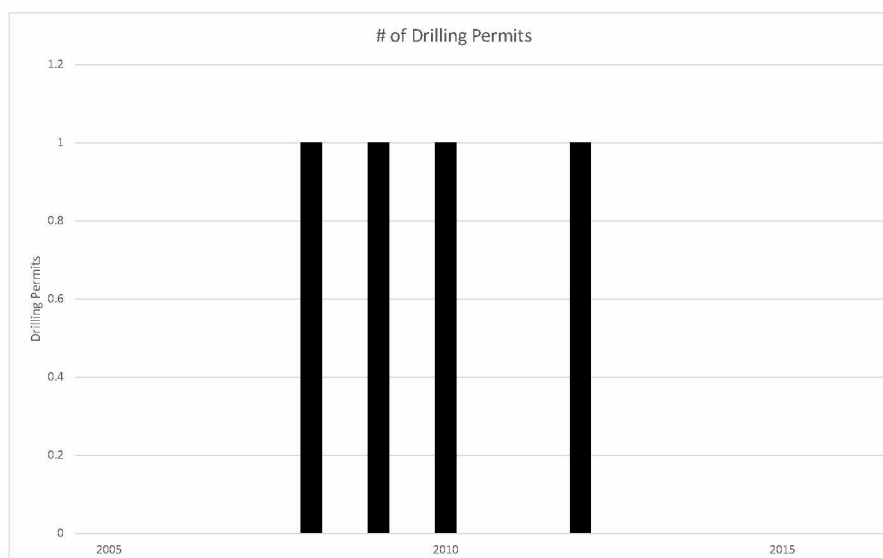


FIGURE 143: OOOGURUK TOROK DRILLING PERMITS BY YEAR

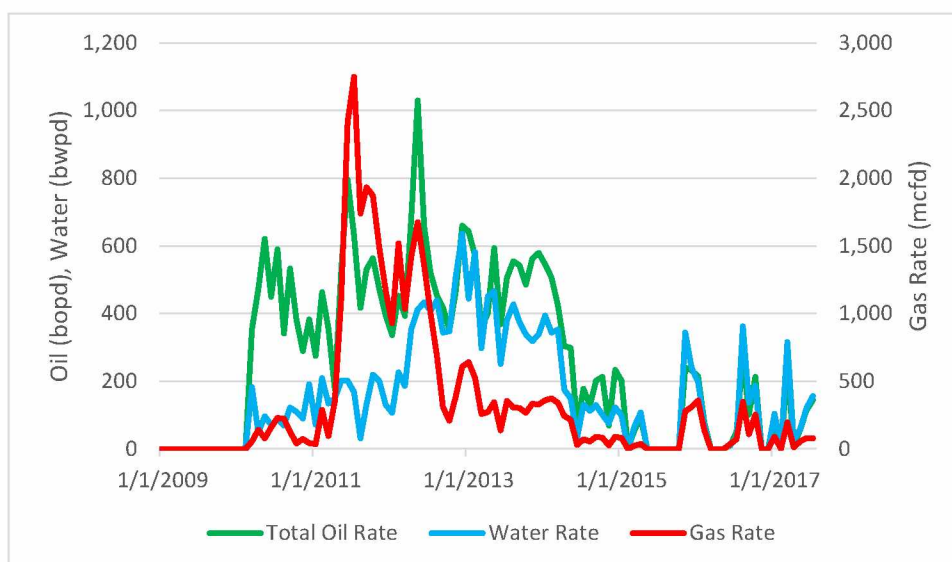


FIGURE 144: OOOGURUK TOROK PRODUCTION

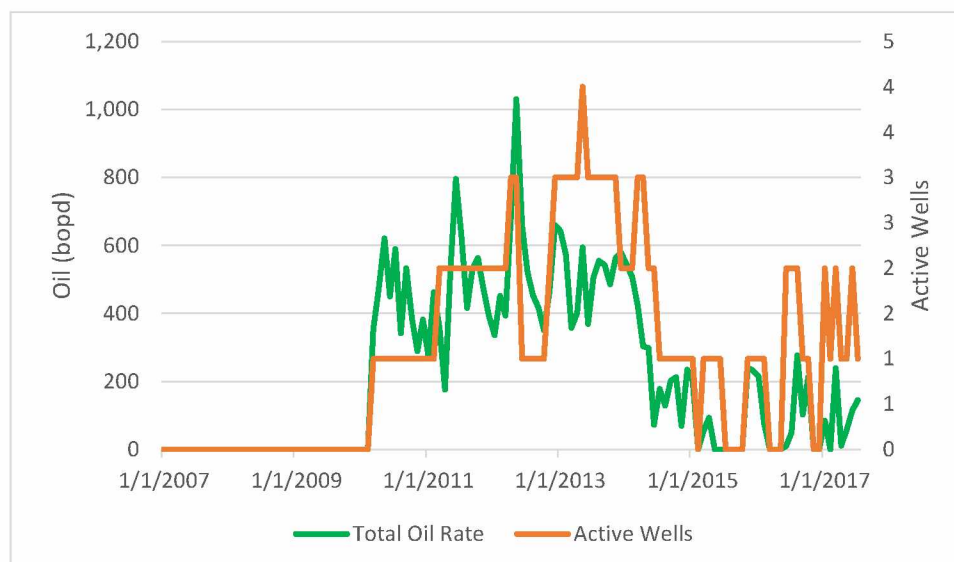


FIGURE 145: OOGURUK TOROK PRODUCTION AND ACTIVE WELLS

## 15. PRUDHOE BAY UNIT

The Greater Prudhoe Bay Unit is the anchor field for all other fields on the North Slope. It can be divided into a set of three field groupings. The primary of which is giant oil field Prudhoe Bay, sometimes referred to as the initial participating area (IPA). Secondly there is the Greater Point McIntyre Area (GPMA), which comprises of the fields to the north of Prudhoe Bay: Lisburne, Pt. McIntyre, Niakuk, Raven, West Beach, and North Prudhoe Bay. Thirdly, the western satellites: Aurora, Borealis, Orion, Polaris, and Midnight Sun.

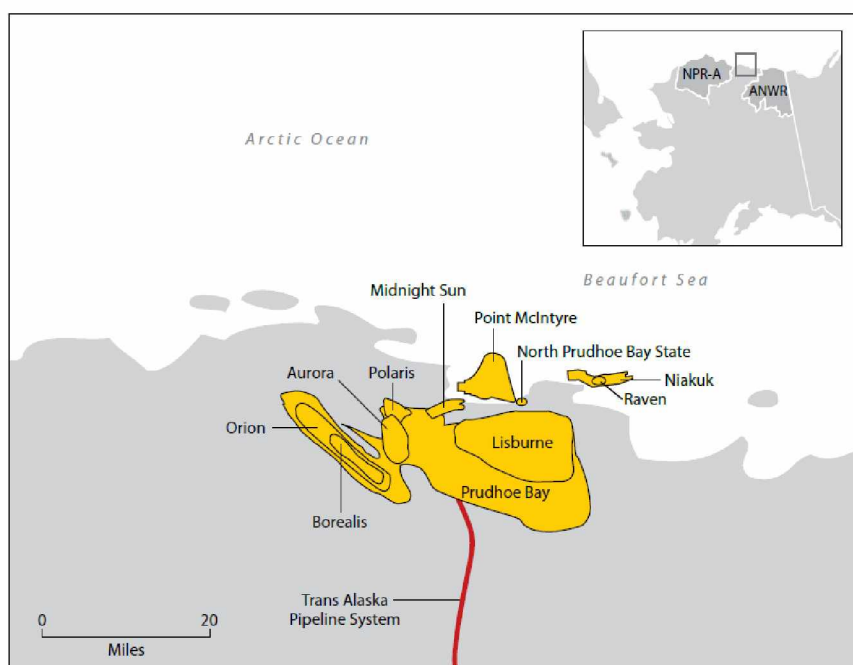


FIGURE 146: GREATER PRUDHOE BAY MAP (CONOCOPHILLIPS, 2017)



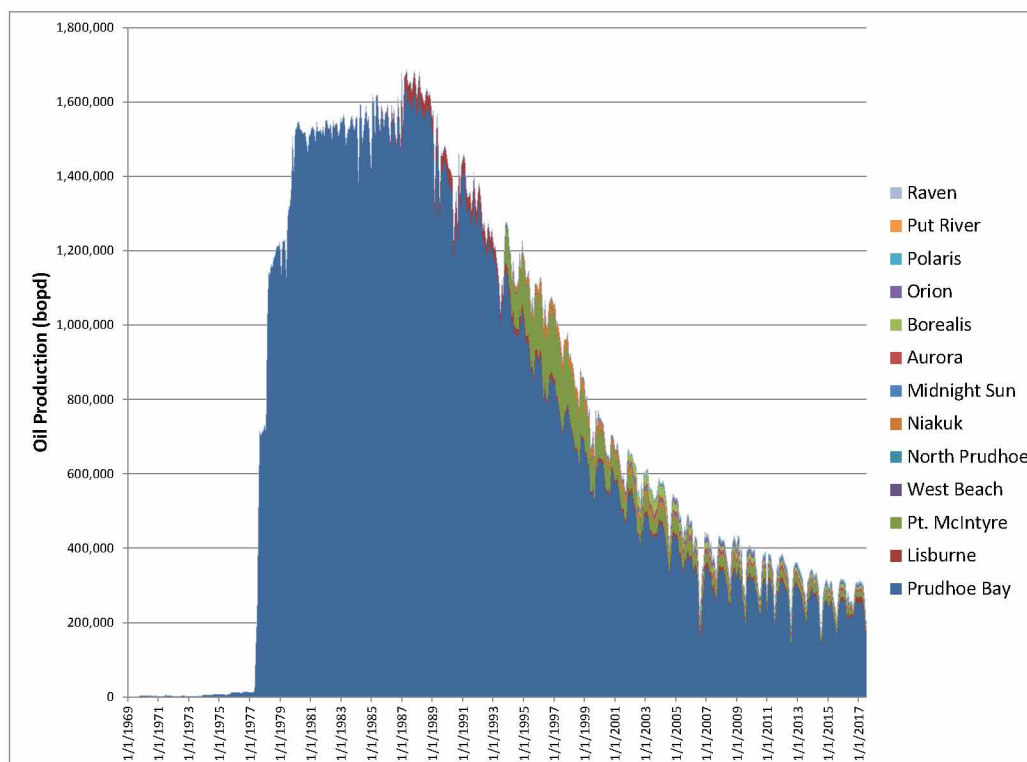


FIGURE 147: PRUDHOE BAY UNIT PRODUCTION

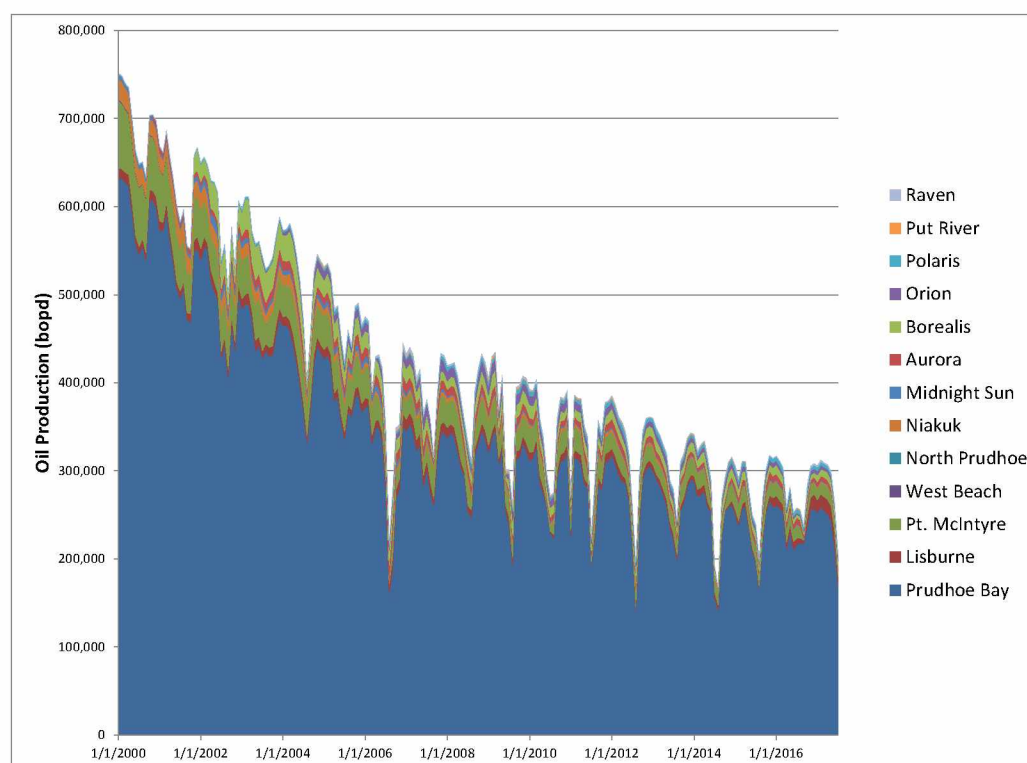


FIGURE 148: RECENT PRUDHOE BAY UNIT PRODUCTION



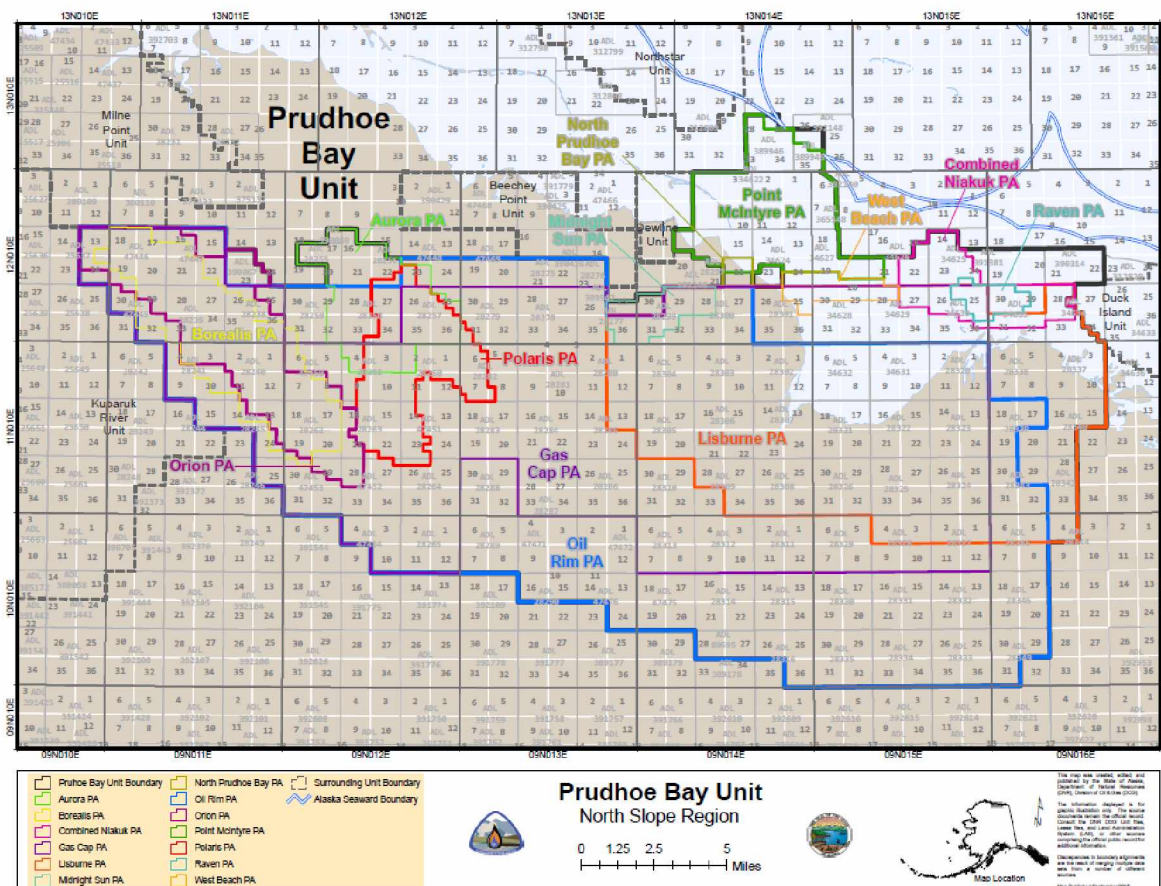


FIGURE 149: PRUDHOE BAY UNIT MAP (ALASKA DEPARTMENT OF NATURAL RESOURCES, 2015)

## 15.1. AURORA

The Aurora field produces from the Kuparuk formation and is located at S pad. Production from the field began in 2000, and the field peaked at 14,000 bopd. The field has made 42 million barrels of oil and is currently producing 5,000 bopd from 30 active wells. The field is developed as a waterflood with MWAG.

This line chart displays three production metrics over time from January 1, 1999, to January 1, 2017. The left y-axis measures Oil (bopd) and Water (bwpd) from 0 to 30,000. The right y-axis measures Gas Rate (mcf/d) from 0 to 60,000. The x-axis shows dates at two-year intervals. The legend indicates: Total Oil Rate (green line), Water Rate (blue line), and Gas Rate (red line). The Gas Rate shows extreme volatility, peaking near 60,000 mcf/d in 2003 and 2007. The Water Rate shows a steady increase, peaking near 24,000 bwpd in 2017. The Total Oil Rate shows a general upward trend, peaking near 14,000 bopd in 2007 and 2017.

Date	Total Oil Rate (bopd)	Water Rate (bwpd)	Gas Rate (mcf/d)
1/1/1999	0	0	0
1/1/2001	5,000	0	18,000
1/1/2003	10,000	2,000	55,000
1/1/2005	10,000	10,000	15,000
1/1/2007	14,000	10,000	45,000
1/1/2009	10,000	12,000	10,000
1/1/2011	8,000	18,000	10,000
1/1/2013	8,000	12,000	10,000
1/1/2015	8,000	18,000	10,000
1/1/2017	14,000	24,000	5,000

**FIGURE 151: AURORA FIELD PRODUCTION**

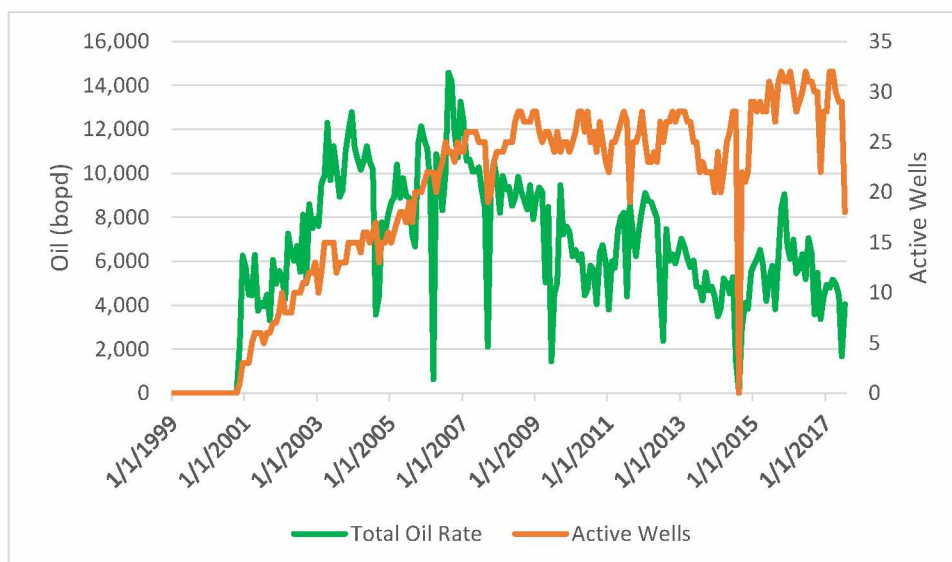


FIGURE 152: AURORA PRODUCTION AND ACTIVE WELL COUNT

## 15.2. BOREALIS

The Borealis field produces from the Kuparuk formation and is located at L, V, and Z pads. Production from the field began in 2001, and the field peaked at 35,000 bopd. The field has made 81 million barrels of oil and is currently producing 8,000 bopd from approximately 50 active wells. The field is developed as a waterflood with MWAG.

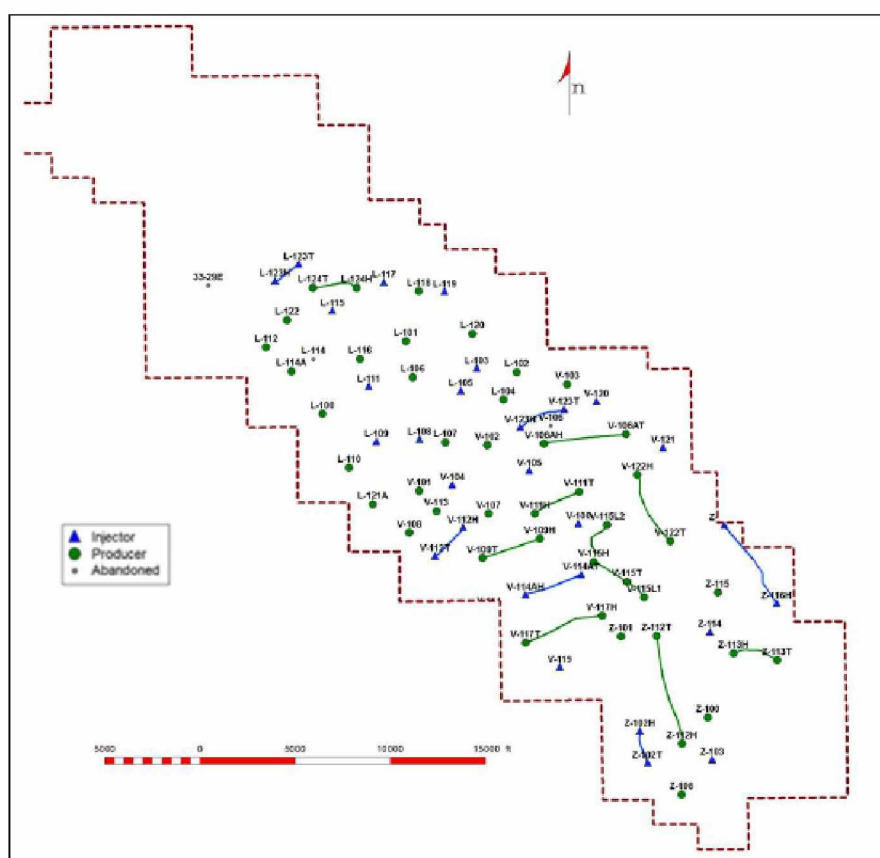


FIGURE 153: BOREALIS WELL MAP (BP EXPLORATION (ALASKA) INC., 2016)

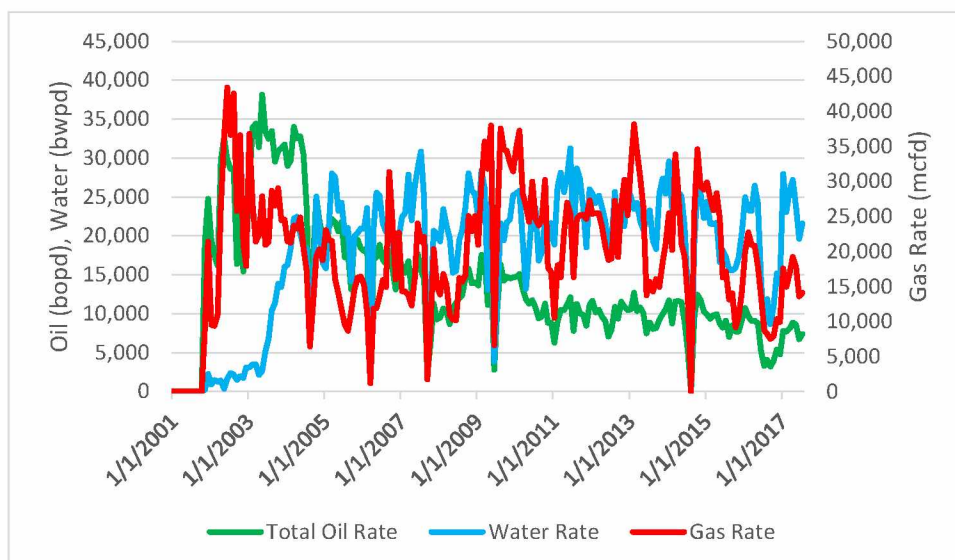


FIGURE 154: BOREALIS FIELD PRODUCTION

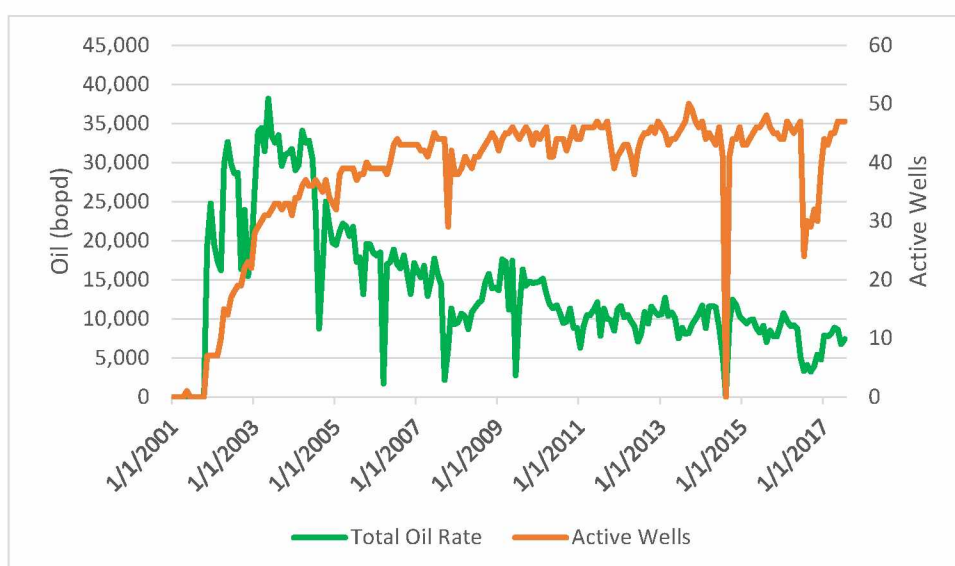


FIGURE 155: BOREALIS PRODUCTION AND ACTIVE WELL COUNT

### 15.3. LISBURNE

The Lisburne Pool was discovered by Arco in 1969 with the drilling of Prudhoe Bay State 1. As this well also discovered the world class Prudhoe Bay, development of Lisburne was put on hold until after Prudhoe Bay was more fully developed. With higher oil prices in the 1980s, and the anticipation of Prudhoe Bay going on decline, interest was renewed. The Lisburne Project was sanctioned in 1984, based on 2D seismic and 12 wells, and development drilling began in 1985. Lisburne Production Center (LPC) came online on December 15<sup>th</sup>, 1986, being the first fully integrated production facility to be brought up on a single sealift (Paige & Dayton, 1987). The Original Oil in Place (OOIP) volumetric estimates range from 2-3 billion barrels, while early material balance work indicates a contributing OOIP of 1.5-2 BBO.



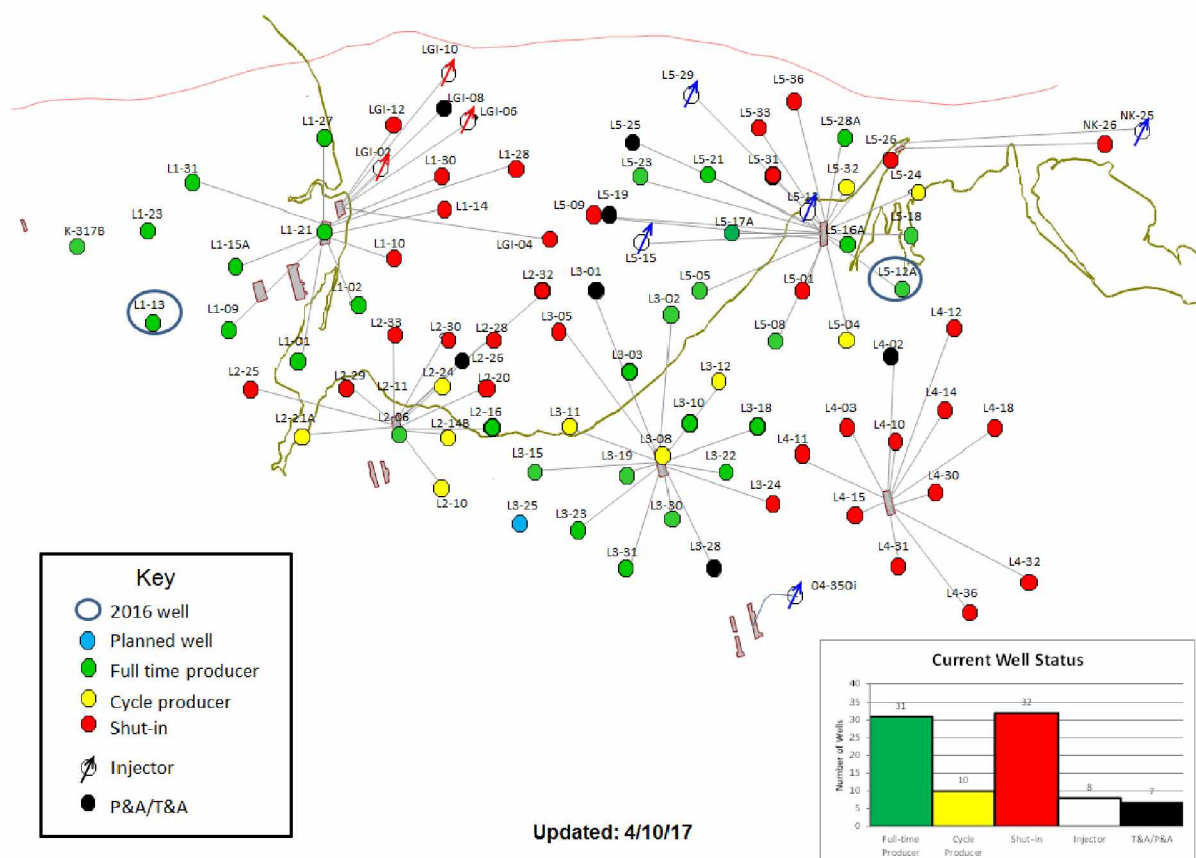


FIGURE 156: LISBURNE 2017 WELL STATUS MAP (BP EXPLORATION (ALASKA) INC, 2017)

### 15.3.1. GEOLOGY

The wells in the Lisburne Pool produce predominantly out of the Wahoo formation, with the exception of NK-25 and NK-26, which lie in a section of the Alapah in the northeastern corner of the pool. As seen in Figure 157, the Wahoo underlies the Kavik Shale and is divided into 7 zones, separated by thin shales. The green shale separates the Wahoo from the Alapah, which is divided 5 zones, and predominantly overlies the Kayak Shale. The Wahoo is predominantly limestone with large packages of dolomite and minor amounts of cherts. Shale intervals within the Wahoo vary in thickness and may be 1-30 feet thick. The dominant rock types are packstones and grainstones, and may be composed of various mixtures of skeletal and non-skeletal lime particles (Paige & Dayton, 1987). All porosity in the Lisburne is secondary porosity, relating to diagenetic effects, either dissolution or dolomitization. The Lisburne field is defined by the Niakuk fault to the north, the Lower Cretaceous Unconformity (LCU) to the east, and a gentle dip to the south and west. The LCU and the Pre Echooka Unconformity (PEU), eroded part of reservoir, and both greatly influenced the diagenetic effects along the top of the formation. This highly porous and permeable zone has historically been referred to as the Sub Alteration Zone (SAZ). Additionally, Lisburne is considered a type 2 fractured carbonate, with essential permeability being supplied by the fractures. The nature of the fractures and complexity geology were greatly underestimated during initial field development. By 1991, at the end of the initial field development, the geologic models pay, fluid contacts, lithology, and fractures had changed greatly compared to the 1984 depiction of Lisburne.

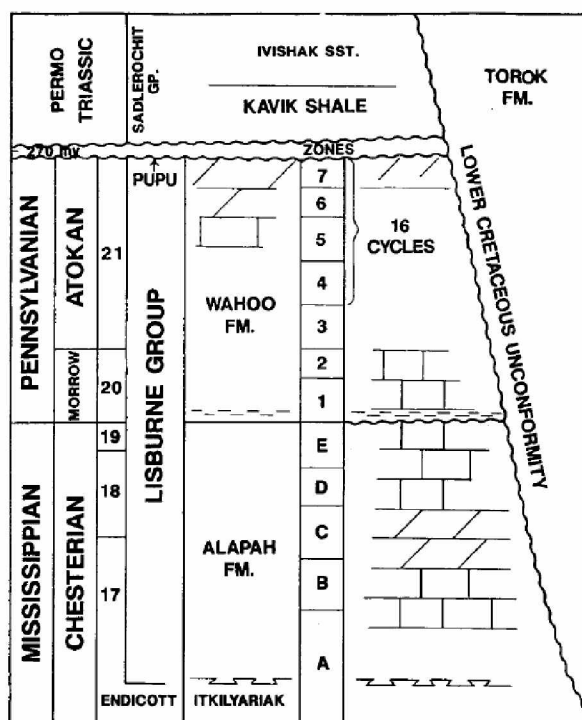


FIGURE 157: LISBURNE STRATIGRAPHY (MISSMAN R, 1991)

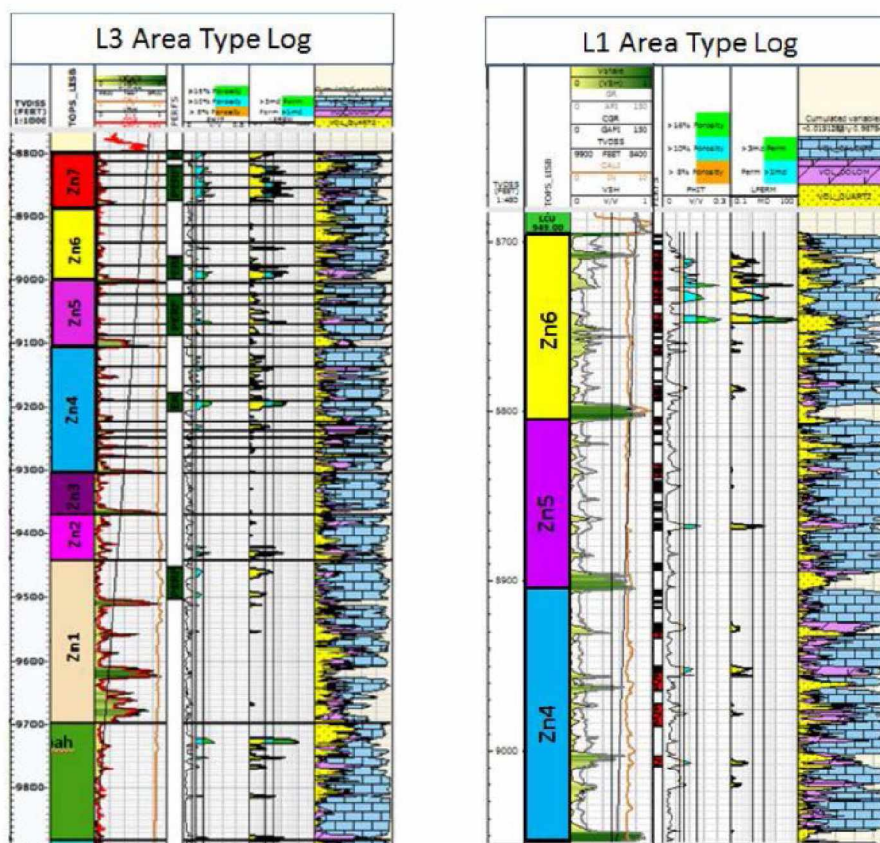


FIGURE 158: LISBURNE TYPE LOGS (MICHIE, SIKS, SAUVE, &amp; WAGES, 2016)

The original 5% porosity cutoff for net pay was based on using the carbonates of the Permian Basin as an analogy. This was later found to be much too low of porosity, with 8-12% being a more acceptable number. A

change in porosity cutoff from 5-10% in the Lisburne drops the effective oil in place by approximately 30% as seen in Figure 162 (Missman R, 1991). The large transition zone in Lisburne lead to a variation in oil water contacts as seen in Figure 161. This is in part due to the extremely tight rock affecting capillary pressures and inconclusive drill stem tests, and difficulty picking oil water contacts from open-hole logs. Current models for the Lisburne reflect a tilting OWC, with the contact being at 9150' in the south, and around 8900' in the northern part of the field. Early fracture view of the Lisburne was that all layers were considered to be uniformly enhanced by small scale fracture systems, with relatively few megafractures (Missman R, 1991). Current Fracture view is a combination of megafractures with the small-scale fractures, and a highly permeable zone along the unconformity. Interception of productive fractures is considered necessary to have a productive well in Lisburne.

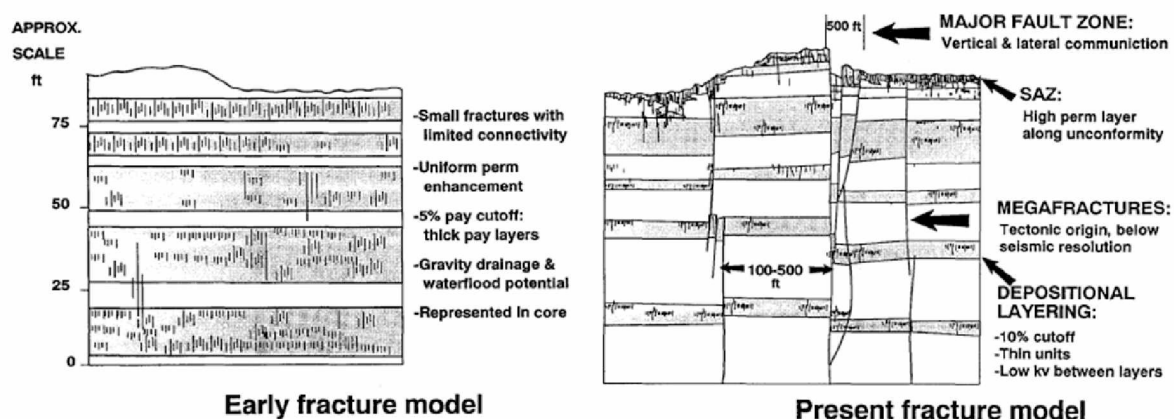


FIGURE 159: 1984 AND 1991 FRACTURE MODELS (MISSMAN R, 1991)

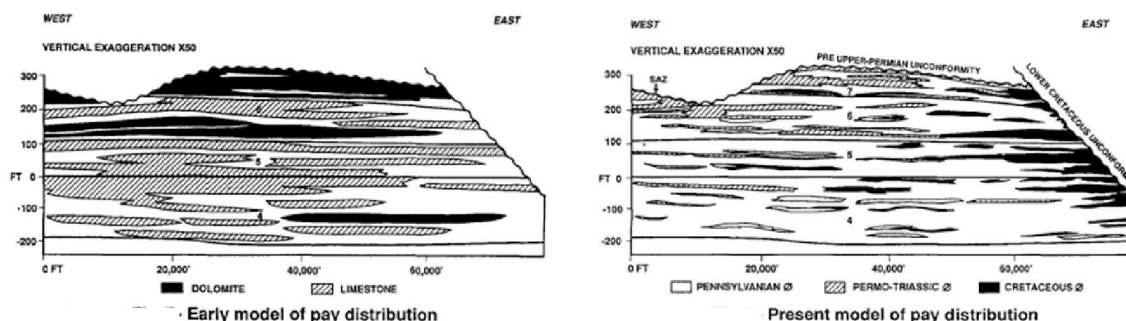


FIGURE 160: 1984 AND 1991 PAY DISTRIBUTION MODELS (MISSMAN R, 1991)



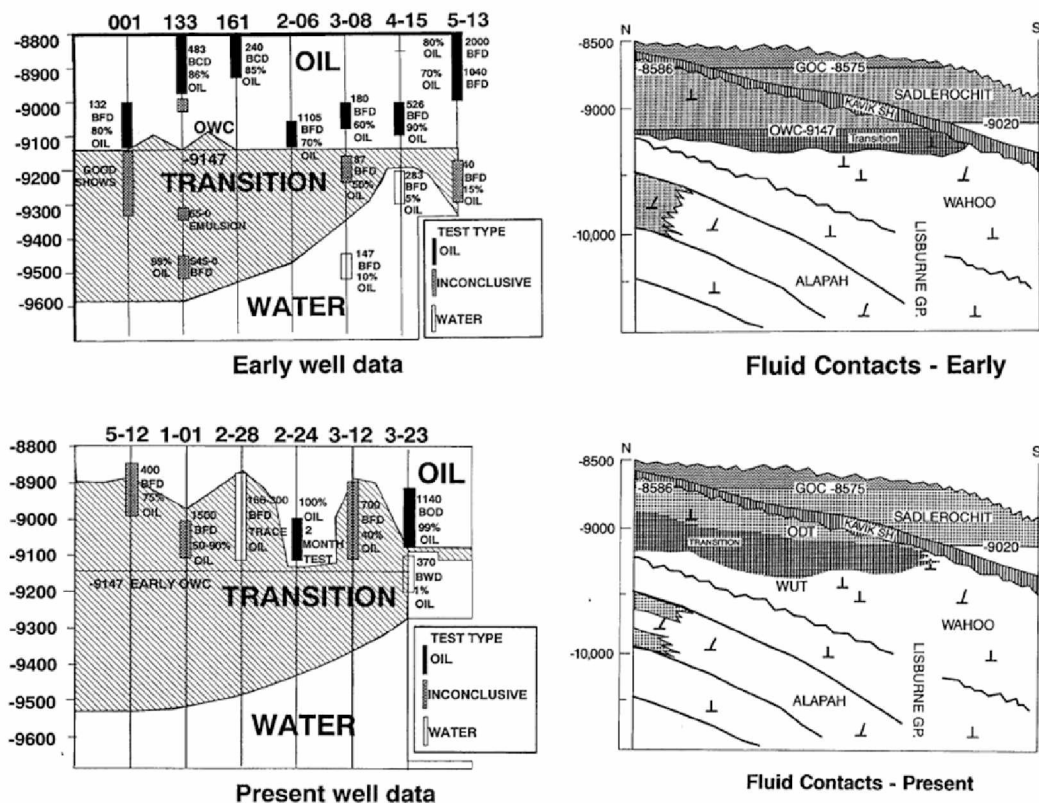


FIGURE 161: LISBURNE FLUID CONTACTS (MISSMAN R, 1991)

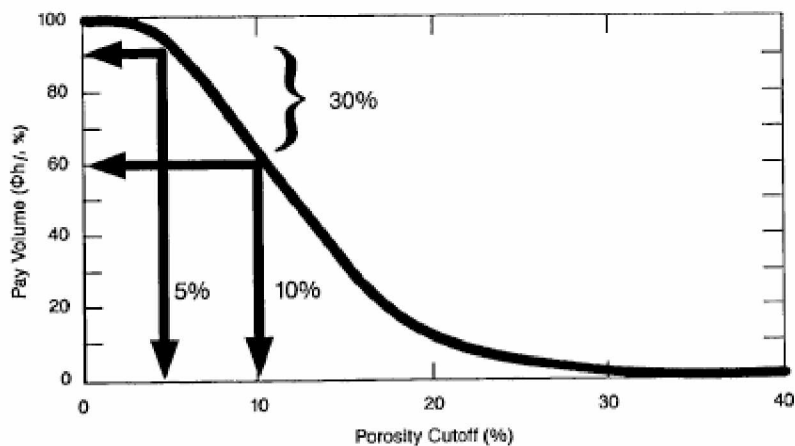


FIGURE 162: POROSITY CUTOFF VS PAY VOLUME (MISSMAN R, 1991)

TABLE 10: 1984 VS 1991 SELECTED RESERVOIR PROPERTIES (MISSMAN R, 1991)

	<u>EARLY</u>	<u>PRESENT</u>
<b>OOIP (MMSTB)</b>	<b>3000</b>	<b>2000</b>
<b>RECOVERY FACTOR</b>	<b>12%</b>	<b>7-10%</b>
<b>RESERVES (PRIMARY C&amp;C, MMSTB)</b>	<b>250-350<sup>1</sup></b>	<b>150-200<sup>2</sup></b>
<b>WELLS</b>	<b>210</b>	<b>&lt;100</b>
<b>PAY CUTOFF (POR UNITS)</b>	<b>5%</b>	<b>10%</b>
<b>OWC (ft)</b>	<b>-9150</b>	<b>-8900-9150 VARIABLE</b>

### 15.3.2. ORIGINAL DEVELOPMENT

The original Lisburne development from 1984 called for over 200 wells on 160 acre spacing, with ultimate development to be infilled at 80 acres with a waterflood. Two-month flow tests were done on four delineation wells to predict reservoir performance. History would show that these delineation wells were coincidentally among the best wells ever drilled in Lisburne, and are not representative of the average well. Figure 163 depicts the original development plan, including 6 producing drillsites and a gas injection drillsite. DS-L6 was to be drilled off of Gull Island, but was never commissioned. Wells were drilled at 60 foot centers on drillsites that were designed contain 32-36 wells and to gather 20 mbopd with a 6,000 scf/bbl GOR (Paige & Dayton, 1987). Drilling in Lisburne stopped in 1991 at approximately 320 acre spacing with the discovery of the nearby Pt. McIntyre and Niakuk fields which would later share the facility with Lisburne. By 1988, two years into development, Lisburne field average GOR was already above 6,000 scf/bbl. The Lisburne Production Center was designed to nominally process 100 mbopd, 600 mmscfd (400 mmscfd initially installed) and 10 mbwpd, with produced gas to be reinjected at LGI and produced water to be injected into a nearby cretaceous disposal well (Paige & Dayton, 1987). The plant was also designed to generate 36 megawatts of electricity and contains an NGL plant to blend with the sales crude, which was started up in June 1987 (Paige & Dayton, 1987). Lisburne monthly production never achieved the expected plateau rates of 100 mbopd, but rather peaked between 40-50 mbopd, and averaged about 5000 bopd since 2010 until the recent drilling campaign. Production forecasts in 1987, even with below expected initial results and 48 well drilled, approximately half of what would actually be drilled in the initial development, still predicted continuation of the 200 well drilling program and a peak production of 75 mbopd, with a cumulative production on primary to be approximately 250-350 mmo by 2010. Today the Lisburne field has produced 187 million barrels, a little more than half what it was expected to deliver. The average expected recovery for a Lisburne well was 1.6 mmo, with a profile seen in Figure 165, which is approximately the delivery of the average Lisburne well to date with 25-30 years of production history. Actual average 10 year cum oil was a little shy of 1.4 mmo. As a whole, Lisburne wells performed poorer than expected, with initial rates predicted on average 75-100% above delivered. Lisburne flow performance is heavily dictated by the matrix and fracture connectivity to the well. Most wells experience a sharp decline as the fractures are depleted, followed by a relatively flat production profile as the matrix begins to contribute to the fracture network. As seen in Figure 166, the average well came on around 1500 bopd, and stabilized around 300 bopd.

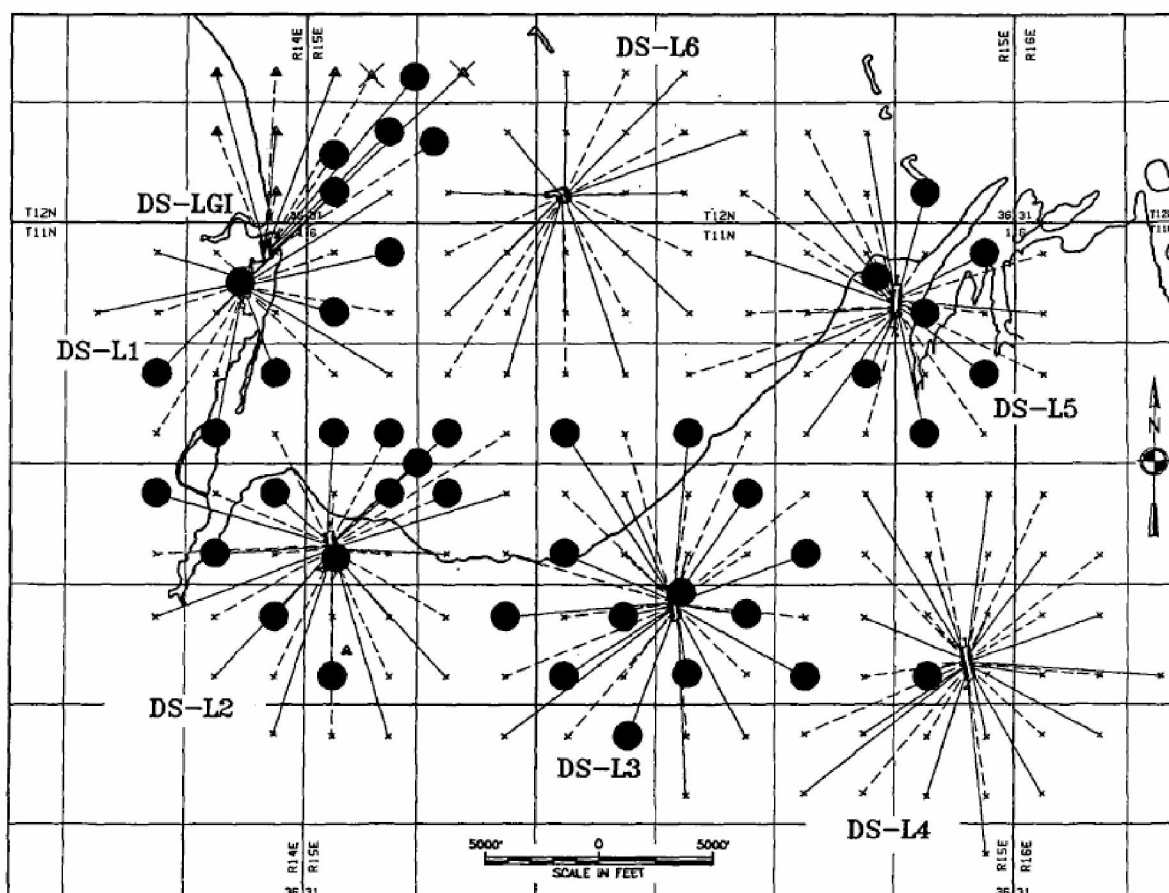


FIGURE 163: INITIAL LISBURNE DEVELOPMENT PLAN WITH WELLS DRILLED BY 1987 HIGHLIGHTED (PAIGE & DAYTON, 1987)

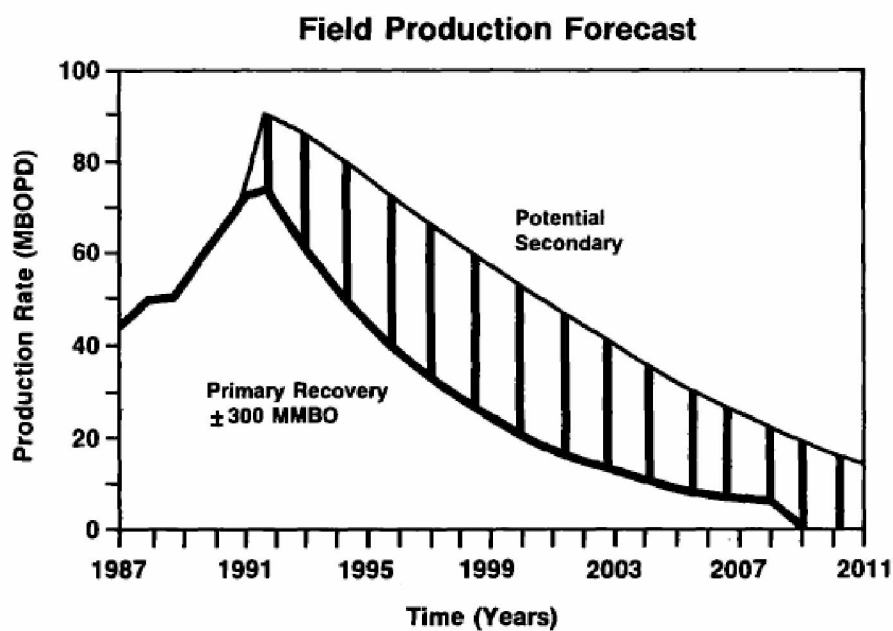


FIGURE 164: LISBURNE PRODUCTION FORECAST 1987 (PAIGE & DAYTON, 1987)

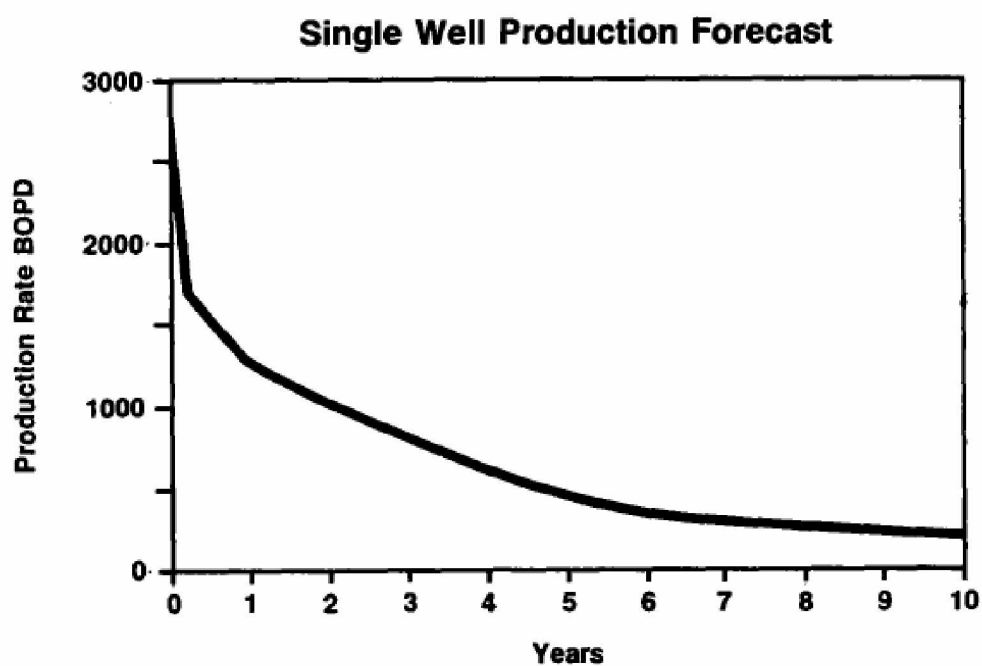


FIGURE 165: SINGLE WELL PRODUCTION FORECAST (PAIGE & DAYTON, 1987)

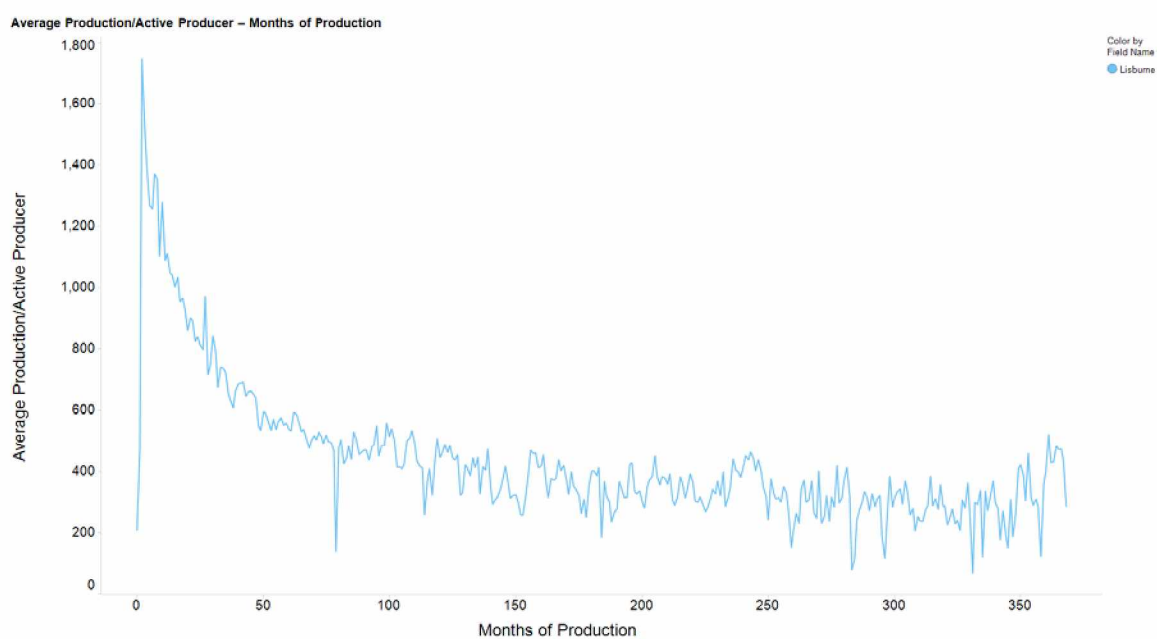


FIGURE 166: LISBURNE AVERAGE SINGLE WELL PRODUCTION HISTORY

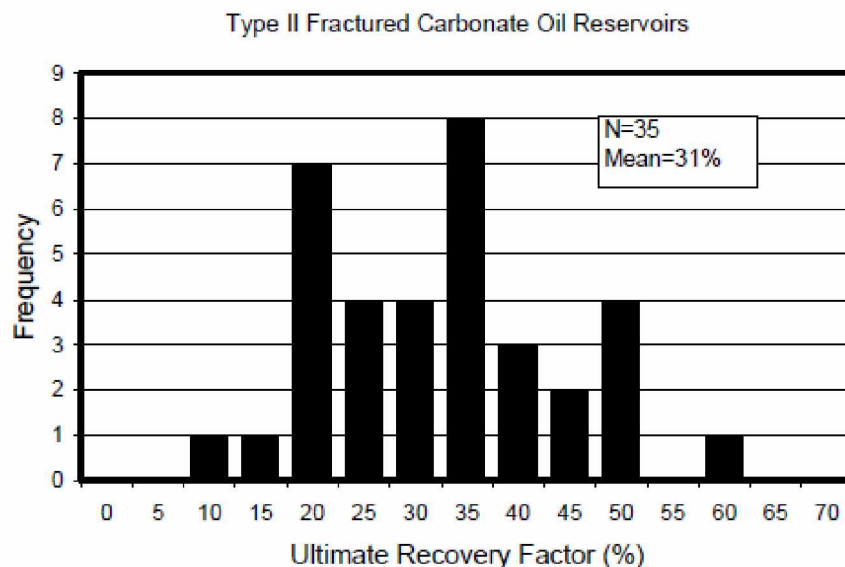


FIGURE 167: ULTIMATE RECOVERY OF TYPE II FRACTURED CARBONATES (QING SUN, SLOAN, & C&C RESERVOIRS, 2003)

### 15.3.3.1980's WATERFLOOD PILOT

Waterflood pilot testing began in 1987 on the L2 drillsite, five months after the field started production, with the hopes of doubling ultimate recovery like other carbonate waterfloods. Water broke through in the first test in as little as 8 days (Missman R, 1991). Other patterns and pilots were tested nearby with mixed, mostly negative results. A total of nearly 9 million barrels of water were injected across nine wells. The pilot was plagued with small oil benefits and quick water breakthroughs. The pilot ended and most wells quickly healed from the water injection, including those which had been injectors.

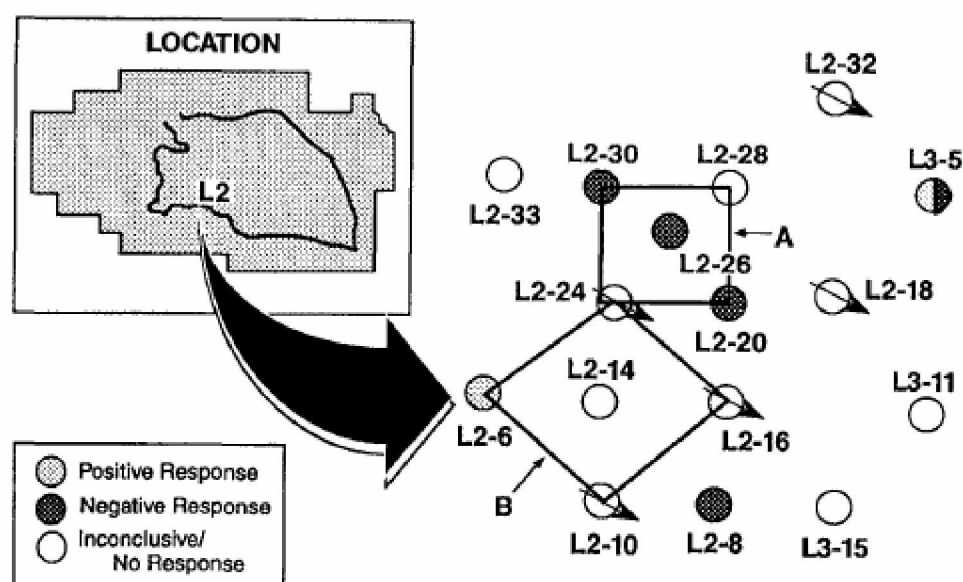


FIGURE 168 L2 WATERFLOOD PILOT (MISSMAN R, 1991)

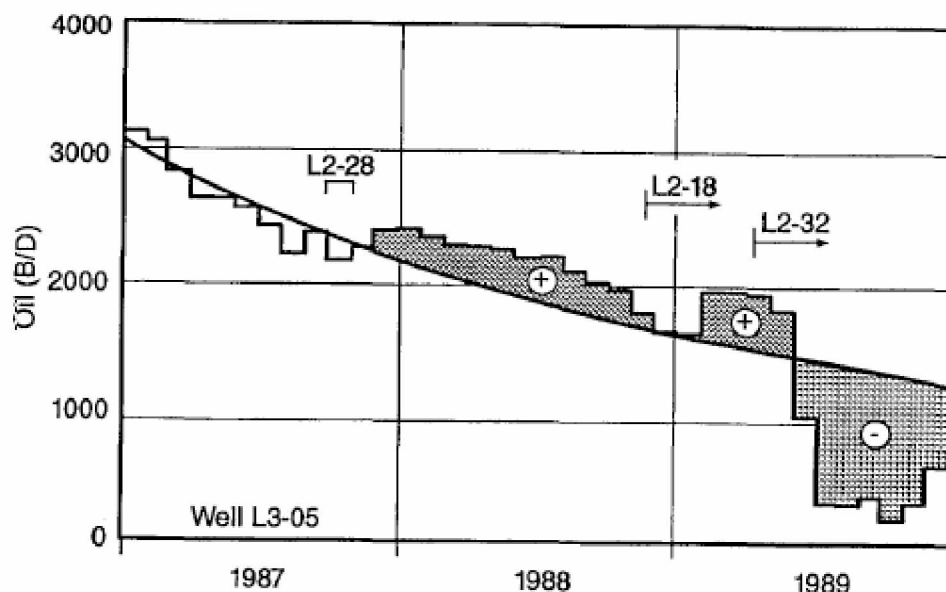


FIGURE 169: L2 WATERFLOOD RESPONSE (MISSMAN R, 1991)

#### 15.3.4. ALAPAH

With the results of the Sag Delta 1 drill stem test, two wells were drilled off of the Niakuk Drillsite to exploit the Alapah there. These wells (NK-25 and NK-26) were drilled in 1994 and 1997 with great initial results. To follow up on this, a well, L1-31 was drilled in 1998 to produce the Alapah in the west. This well produced mostly water and was recompleted across the Wahoo (AOGCC, Well Image Files, 2015) (AOGCC, Production Database, 2015).

#### 15.3.5. LISBURNE COIL SIDETRACK CAMPAIGN

From 2003-2006 a coil sidetrack program was developed and executed. Six were wells drilled in 2003 and 2004 were on average approximately 1500 feet in length. The results have been mixed by area and program. Western Periphery wells L1-15A and K-317B have produced 2.2 mmbo and 1.7 mmbo respectively. L5-17A which replaced a very productive parent well has made 1.7 mmbo. The wells drilled off of L2 however, have only made 0.01 mmbo (L2-14A) 0.30 mmbo (L2-14B) and 0.27 (L2-21A) mmbo. In 2006 two underbalanced multilateral coil wells were drilled. These wells were able to double the rate of penetration (ROP) of the previous coil wells, but were 40% over budget. As it was underbalanced drilling, they were able to produce 14,000 barrels of oil while drilling (Johnson, et al., 2007). These wells have done better than the L2 coil wells, but have not produced as much as the L1-15A, K-317B or L5-17A even though they are large multilateral underbalanced wells. L5-16A has made 0.62 mmbo and L5-28A has made 0.56 mmbo.

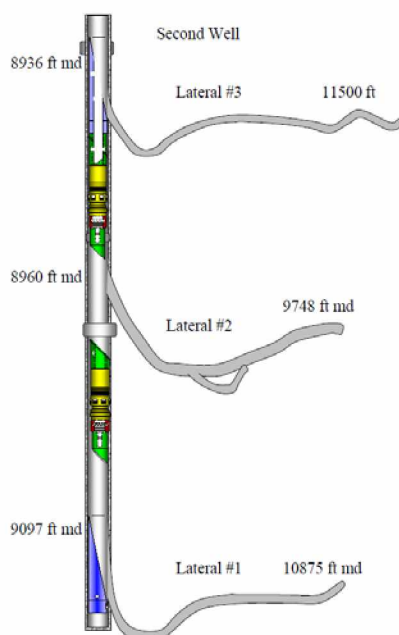


FIGURE 170: L5-16A COMPLETION (JOHNSON, ET AL., 2007)

#### 15.3.6. CURRENT LISBURNE WATERFLOOD PILOT

On July 14<sup>th</sup>, 2008, the Lisburne Gas Cap Water Injection Pilot commenced in L5-29 with the purpose to provide more reservoir pressure support and has injected of 21 MMBW. Water breakthrough has since reached offset wells L5-28, L5-32, L5-33, and L5-36. A peripheral water injector was drilled in May 2012 and has injected 2.6 MMBW, with no wells reporting waterflood breakthrough. Pattern pilot wells L5-15 and L5-13 were converted from producers to injectors in March 2013, with no offset seawater breakthrough being detected in L5-16A. These were converted to try to capture the learnings of the L2 pilot, by injecting at lower rates in a more favorable section of the reservoir. NK-25, an Alapah well, was also converted in March 2013, creating a producer-injector pair in the Alapah, with confirmed seawater breakthrough in the offset Alapah well, NK-26. Although there have been some recent water breakthroughs, it is considered a great improvement on the L2 waterflood pilot which had rapid water breakthrough. Benefits of the L5 waterflood pilot have been an increase in pressure and decreases in GOR which has led to improved producer ontimes and less facility backout.

#### 15.3.7. CURRENT LISBURNE DRILLING DEVELOPMENT

In 2015, three wells L1-23, L3-10 and L3-10 were drilled and completed. These utilized a rotary rig drilling long (up to ~3000') wells in a "U" shape, cross cutting the upper Wahoo zones. These utilized swell packers and sliding sleeves for stimulation and potentially fluid isolation. Fluid isolation was recognized early on in the Lisburne Development, with many of the wells isolated the top zone from the lower zone utilizing a ported nipple and isolation packers. A combination of acid stimulation and hydraulically fracturing was used on L3-03 and L3-10, with the stimulation type being determined by lithology and fault/fracture description. L1-23 was only acid stimulated. This well design takes advantage of the more productive upper zone along the unconformity, while also stimulating historically less productive lower zones (Michie, Siks, Sauve, & Wages, 2016). In 2016 this campaign was extended and L1-13 and L5-12A were drilled, with L3-25 being drilled in 2017. Initial production results from this campaign are comparable to the original development wells 30 years earlier. This drilling campaign, in combination with wellwork and facility projects in GPMA tripled production at Lisburne and reset decline by 20 years as seen in Figure 175.



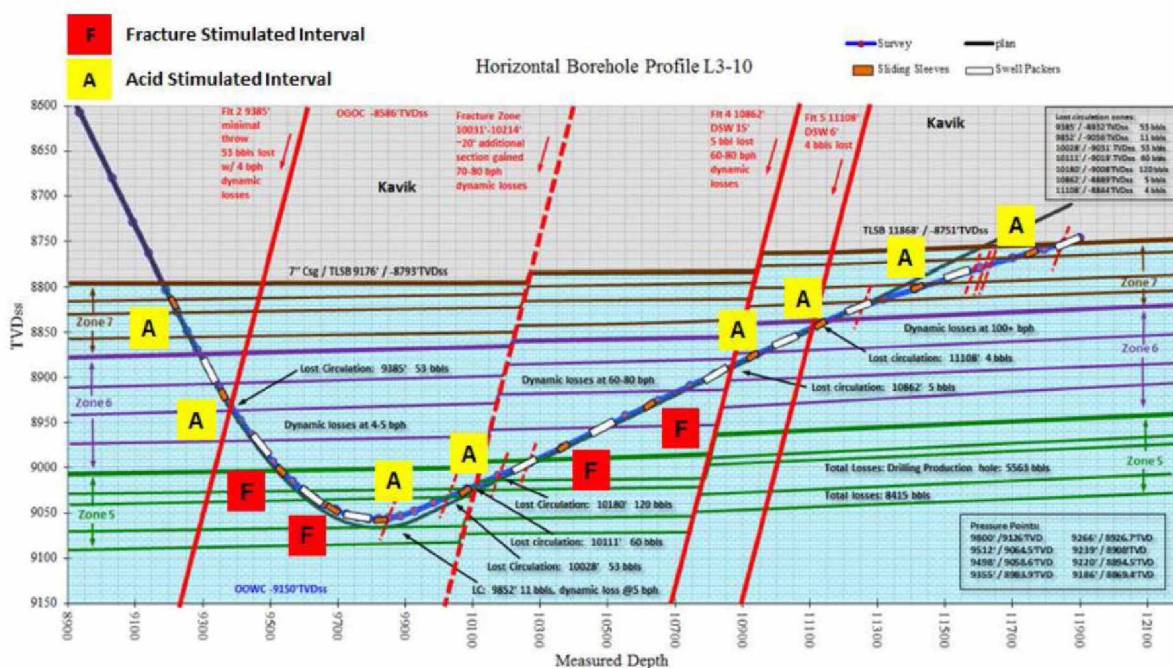


FIGURE 171: L3-03 DIAGRAM OF COMPLETION AND STIMULATION (MICHIE, SIKS, SAUVE, &amp; WAGES, 2016)

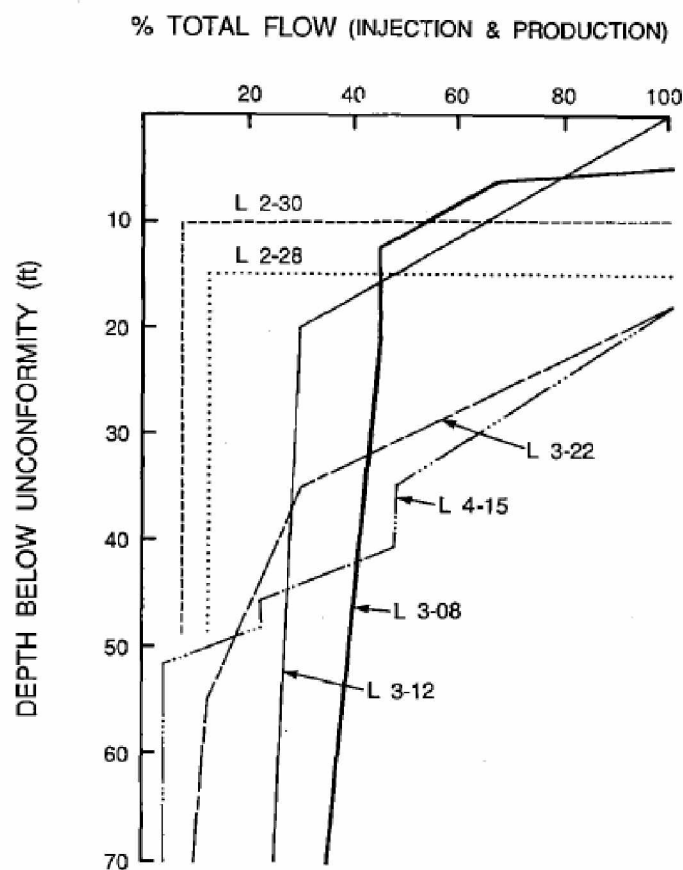


FIGURE 172: LISBURNE PRODUCTION/INJECTION PROFILES (BELFIELD, 1988)

### Typical Lisburne Completion

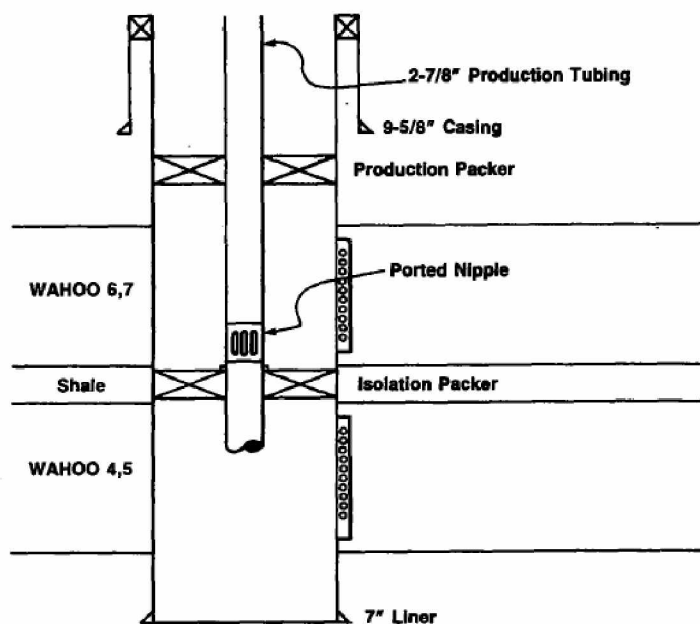


FIGURE 173: TYPICAL COMPLETION OF ORIGINAL DEVELOPMENT WELLS (PAIGE & DAYTON, 1987)

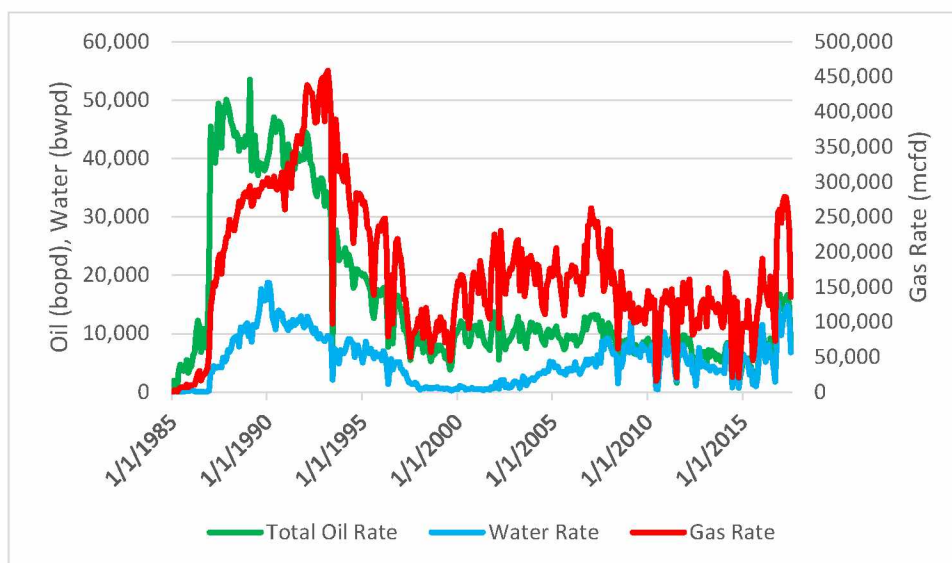


FIGURE 174: LISBURNE FIELD PRODUCTION

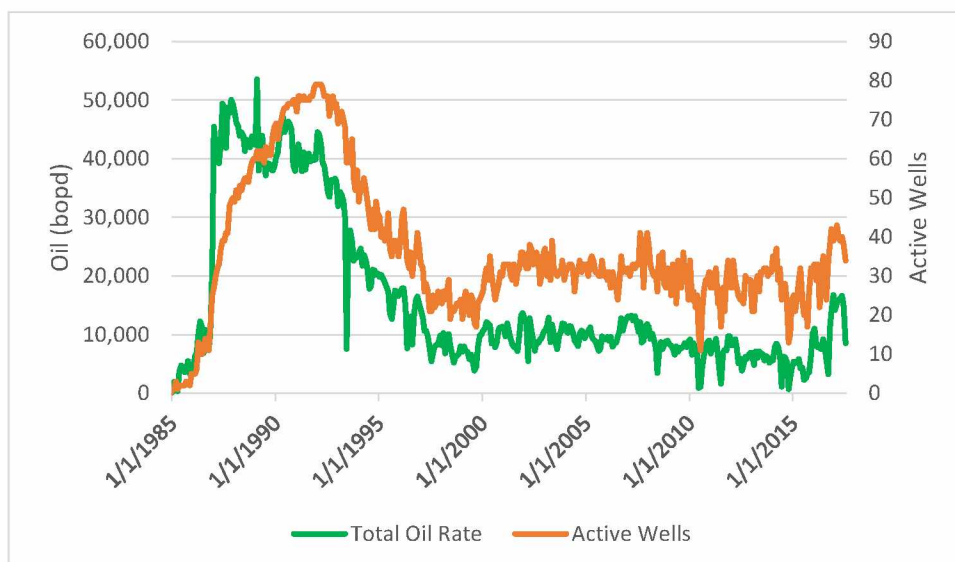


FIGURE 175: LISBURNE PRODUCTION AND ACTIVE WELL COUNT

#### 15.4. MIDNIGHT SUN

The Midnight Sun field produces from the Kuparuk formation and is located at E pad, with an additional injector drilled from P1 in 2015 to inject miscible injectant (MI) and implement a MWAG flood. Production from the field began in 1998, and the field peaked at 12,000 bopd. The field has made 21 million barrels of oil and is currently producing 1,000 bopd from 5 active wells.

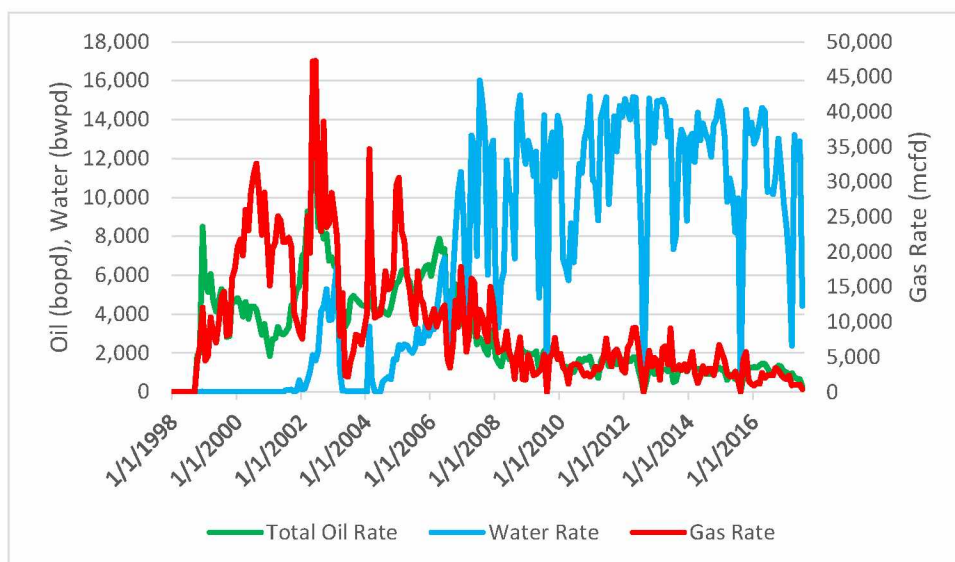


FIGURE 176: MIDNIGHT SUN FIELD PRODUCTION

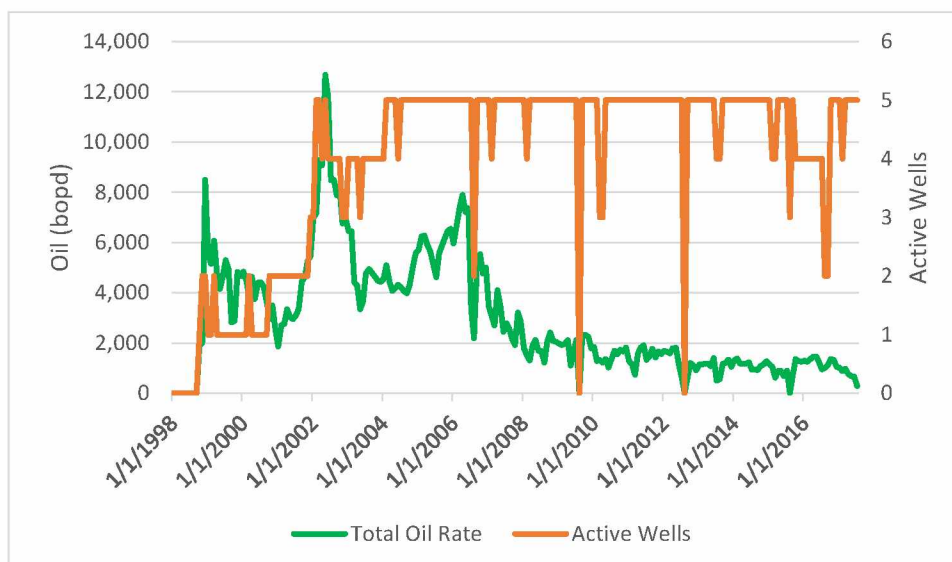


FIGURE 177: MIDNIGHT SUN PRODUCTION AND ACTIVE WELL COUNT

### 15.5. NORTH PRUDHOE BAY

The North Prudhoe Bay Field is located in the Greater Pt. McIntyre Area within the Prudhoe Bay Unit. The field was discovered in 1970 with the North Prudhoe Bay State 1 well, but today consists of a single inoperable well, WB-03, sometimes referred to as NP-03. It is an Ivishak/Sag play, with most of the historical production coming from the Ivishak. After the watercut rose in the Ivishak interval, a fracture treatment was performed in 1998 in the Sag River formation. This has since led to operational difficulties with continued proppant production and the well has been remained shut in since 2000 due to safety concerns. The area was covered in a 2014/2015 seismic survey; however, the area faces challenges due to compartmentalization, fluid uncertainty, and structural complexity (BP Exploration (Alaska) Inc., 2017).

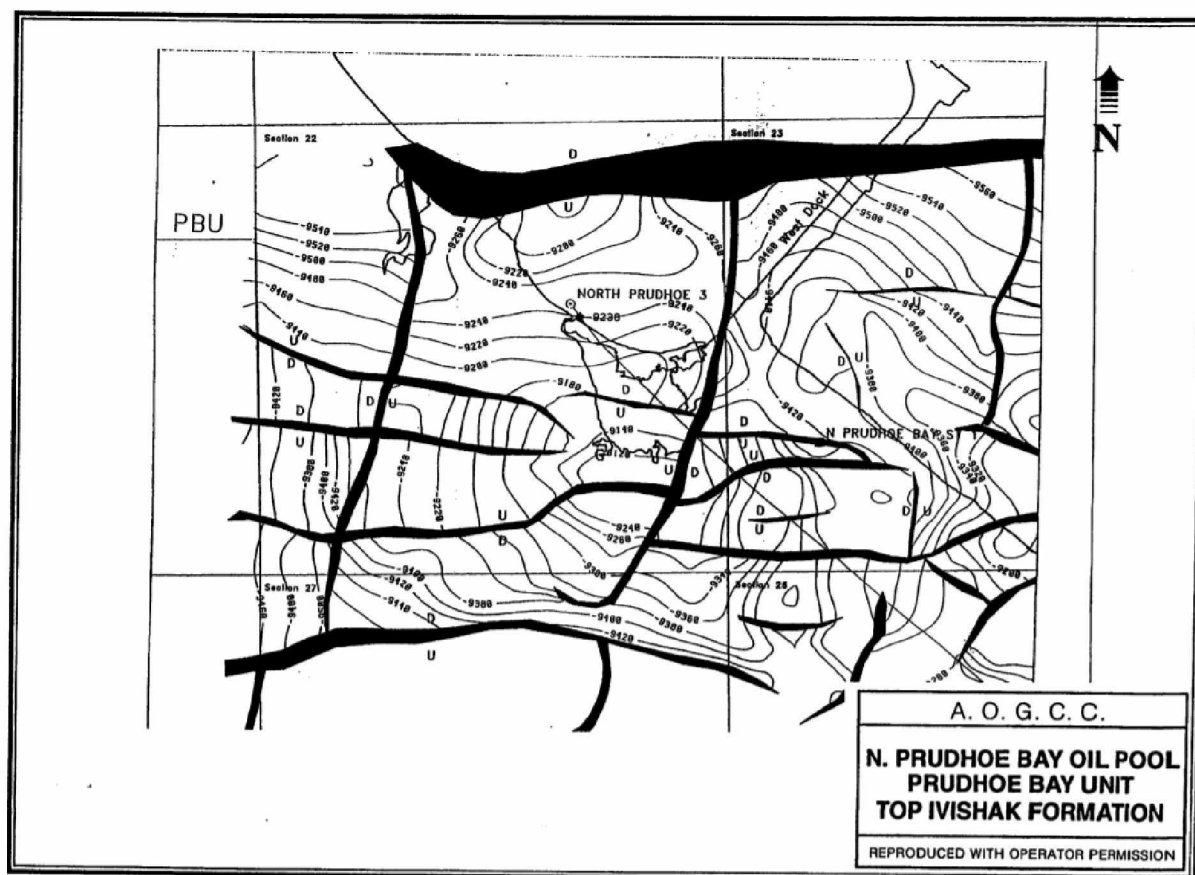


FIGURE 178: NORTH PRUDHOE BAY STRUCTURE MAP (AOGCC, 2000)

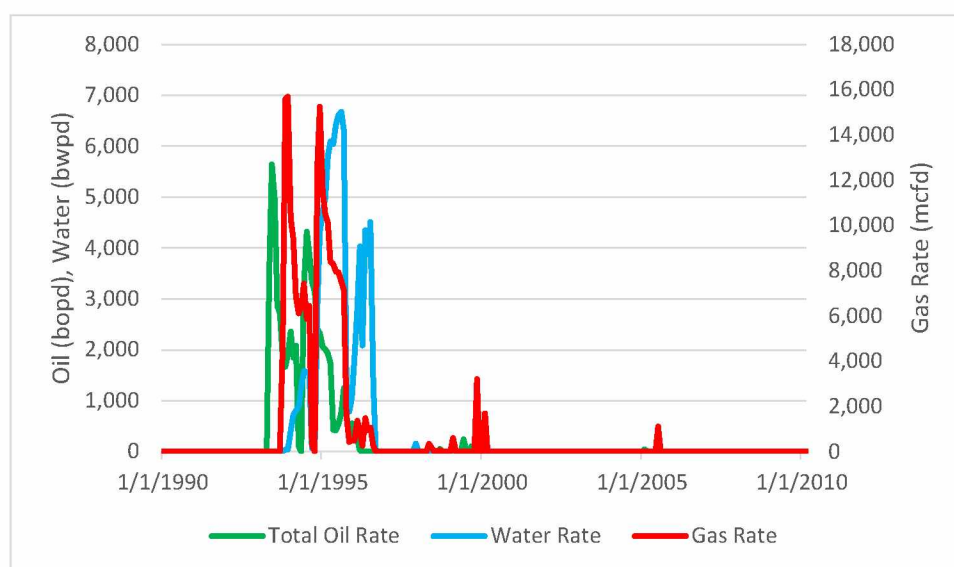


FIGURE 179: NORTH PRUDHOE BAY PRODUCTION



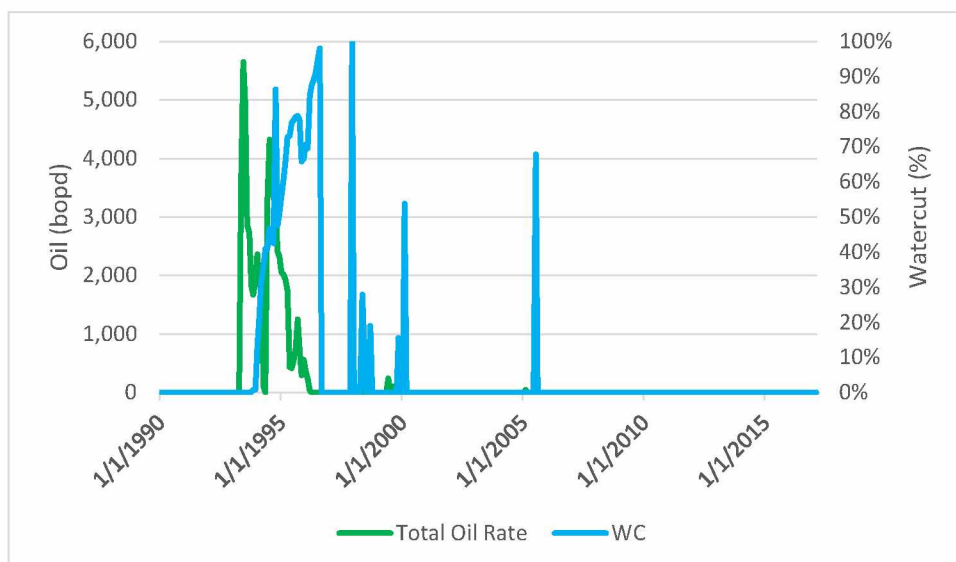


FIGURE 180: NORTH PRUDHOE BAY PRODUCTION AND WATERCUT

## 15.6. ORION

The Orion field produces from the Schrader Bluff formation and is located at the L and V pads. Production from the field began in 2002, and the field peaked at 14,000 bopd. The field has made 34 million barrels of oil and is currently producing 4,000 bopd from approximately 30 active wells. The field is developed as a waterflood with MWAG.

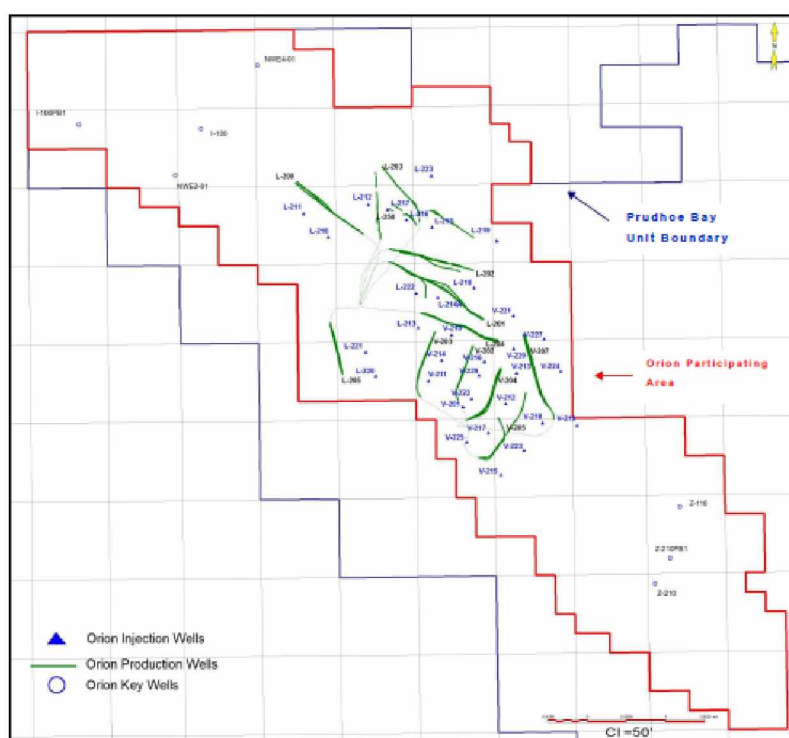


FIGURE 181: ORION WELL MAP (BP EXPLORATION (ALASKA) INC., 2016)



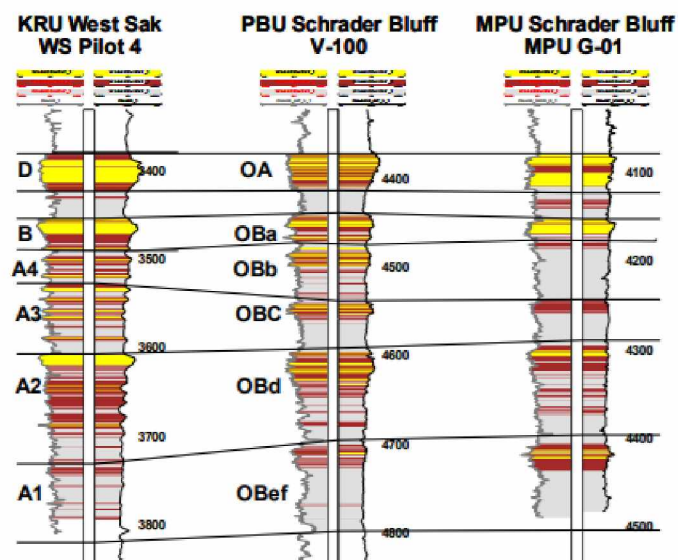


FIGURE 182: SCHRADER BLUFF TYPE LOG (MCGUIRE, REDMAN, JHAVERI, YANCEY, & NING, 2005)

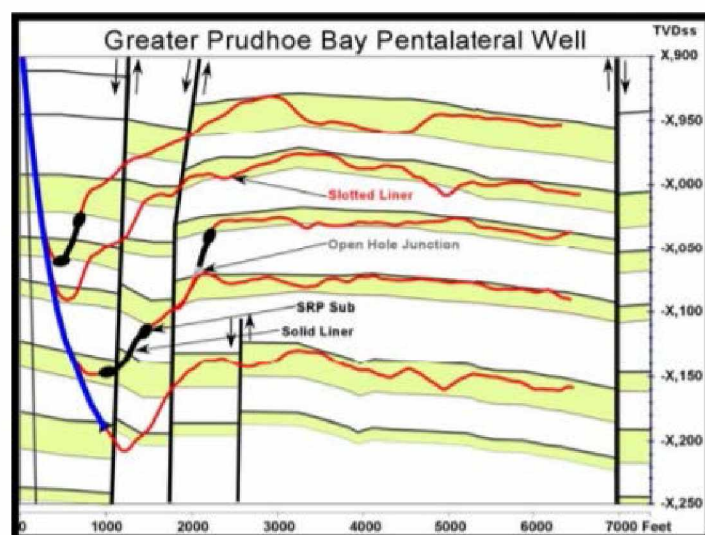


FIGURE 183: EXAMPLE COMPLETION OF A SCHRADER BLUFF MULTI-LATERAL WELL (TRIOLO, DAVIS, BUCK, FREYER, & SMITH, 2005)

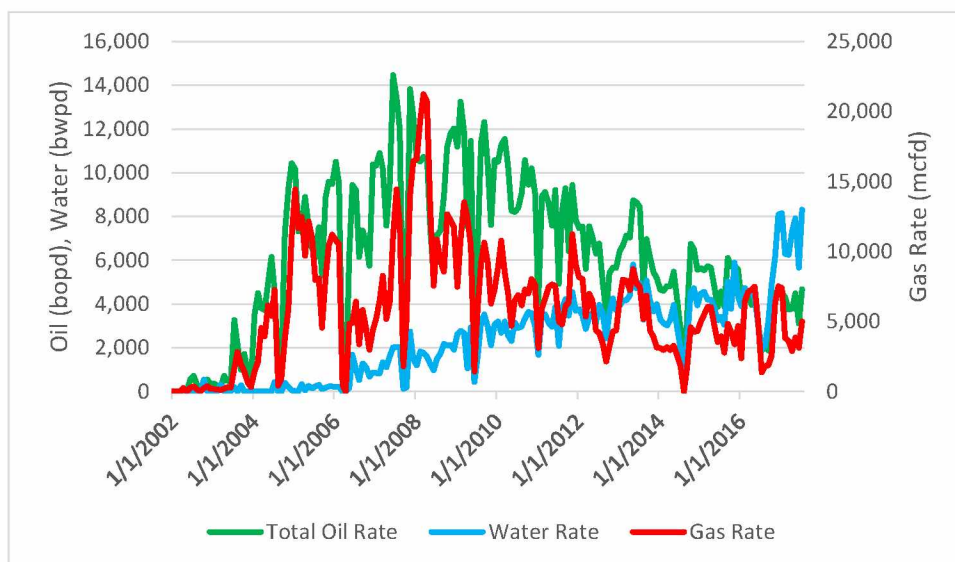


FIGURE 184: ORION FIELD PRODUCTION

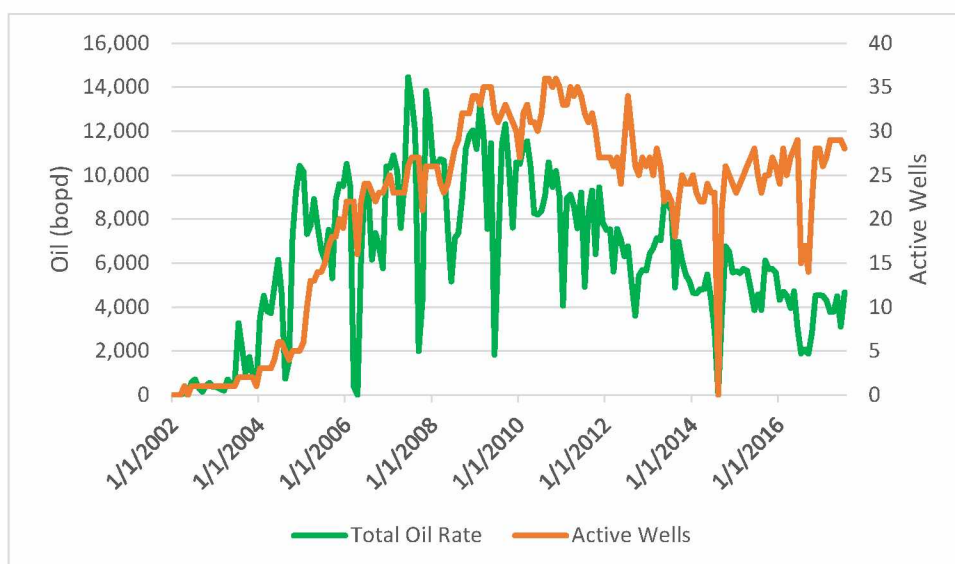


FIGURE 185: ORION PRODUCTION AND ACTIVE WELL COUNT

## 15.7. POLARIS

The Polaris field produces from the Schrader Bluff formation and is located at the S and W pads. Production from the field began in 1999, and the field peaked over 6,000 bopd. The field has made 2 million barrels of oil and is currently producing 3,500 - 4,000 bopd from approximately 24 active wells. The field is developed as a waterflood with MWAG.

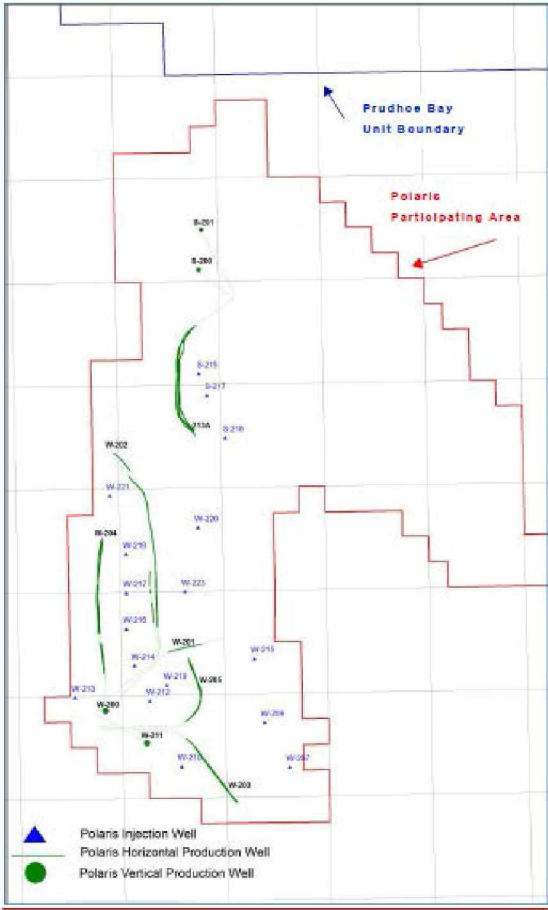


FIGURE 186: POLARIS WELL MAP (BP EXPLORATION (ALASKA) INC., 2016)

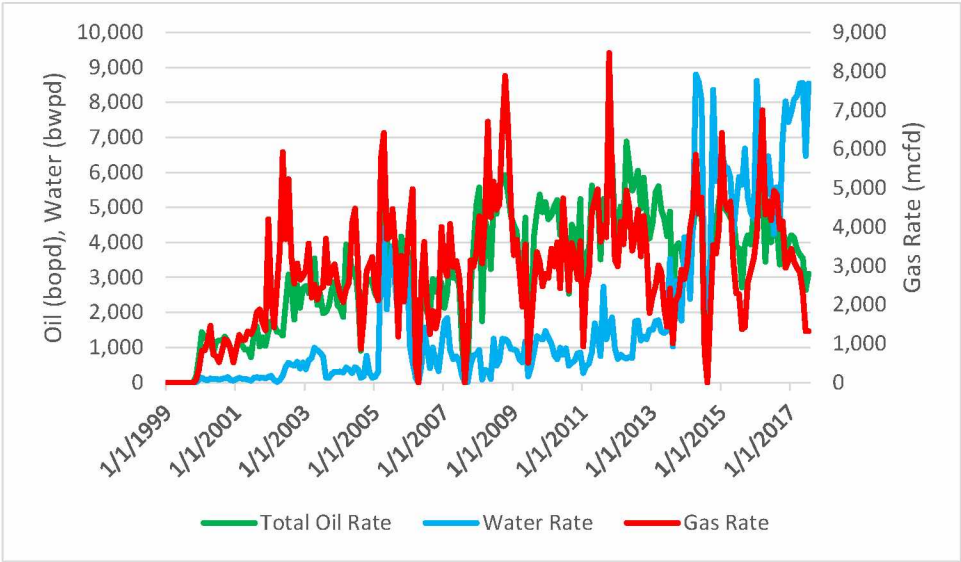


FIGURE 187: POLARIS FIELD PRODUCTION

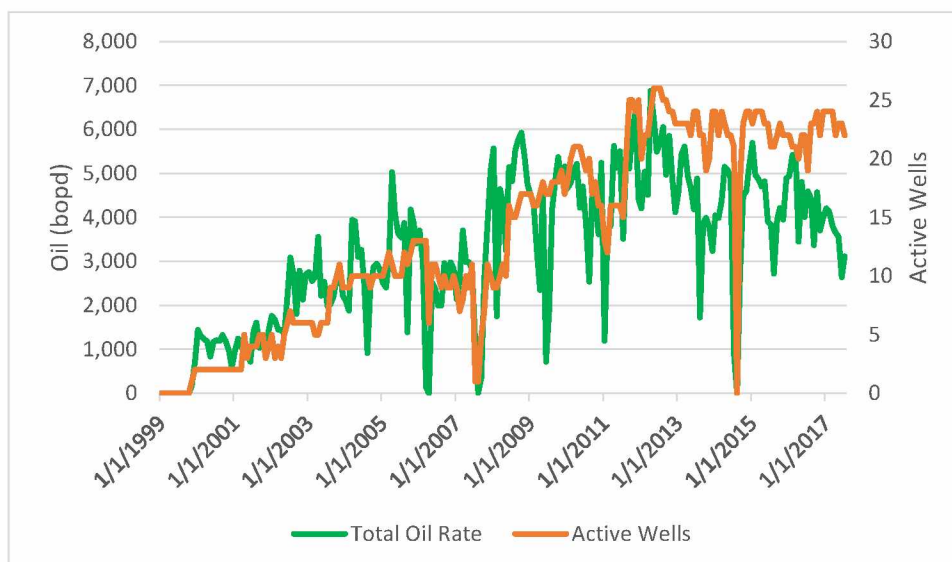


FIGURE 188: POLARIS PRODUCTION AND ACTIVE WELL COUNT

## 15.8. PRUDHOE BAY

Prudhoe Bay was discovered in 1969 with the drilling of Prudhoe Bay State 1 and became the discovery that changed Alaska. It produces from the Ivishak and Sag River formations. The field came on production in June 20<sup>th</sup>, 1977, 40 years ago this past summer. Production peaked in 1987 producing 1.6 million barrels of oil per day, and the field has produced an astonishing 12.4 billion barrels of oil, 70% of all oil that has been produced on the North Slope. The field has had continual development drilling since discovery with 2,600 wells drilled. This number includes sidetrack wells, where the parent bore is often abandoned. Prudhoe is currently producing about 240,000 bopd from 850 active wells, about 45% of current North Slope production. Due to seasonal temperature variations and facility constraints, Prudhoe Bay exhibits a production profile that reflects the seasonal temperature, as the facilities are able to compress more gas during the cold arctic winters. The massive field utilizes multiple depletion mechanisms to maximize reservoir productivity and recovery. The field has a large gas cap, but without a gas export line, the produced gas is reinjected in the gas cap or injected in the waterflood for enhanced oil recovery. In 2016, 2.4 trillion cubic feet, or an average of 6.5 billion standard cubic feet a day was reinjected. Most wells in Prudhoe Bay can be considered to be producing from under the gas cap utilizing gravity drainage as a depletion mechanism, are in the waterflood area, or deplete by a combination of both. Prudhoe Bay's waterflood section utilizes high graded produced gas as miscible injectant for a MWAG flood. The Prudhoe Bay waterflood is mostly developed with inverted nine-spot patterns. Additionally, a Gas Cap Water Injection (GCWI) project that began in 2002 has helped to stabilize reservoir pressures.

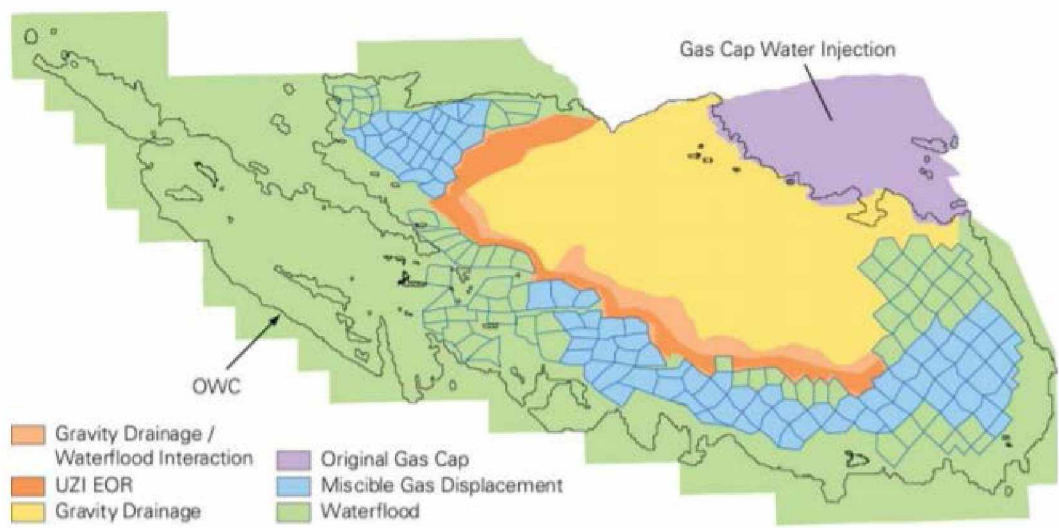


FIGURE 189: PRUDHOE BAY RECOVERY MECHANISMS MAP (BRODIE, JHAVERI, MOULDS, & HETLAND, 2012)

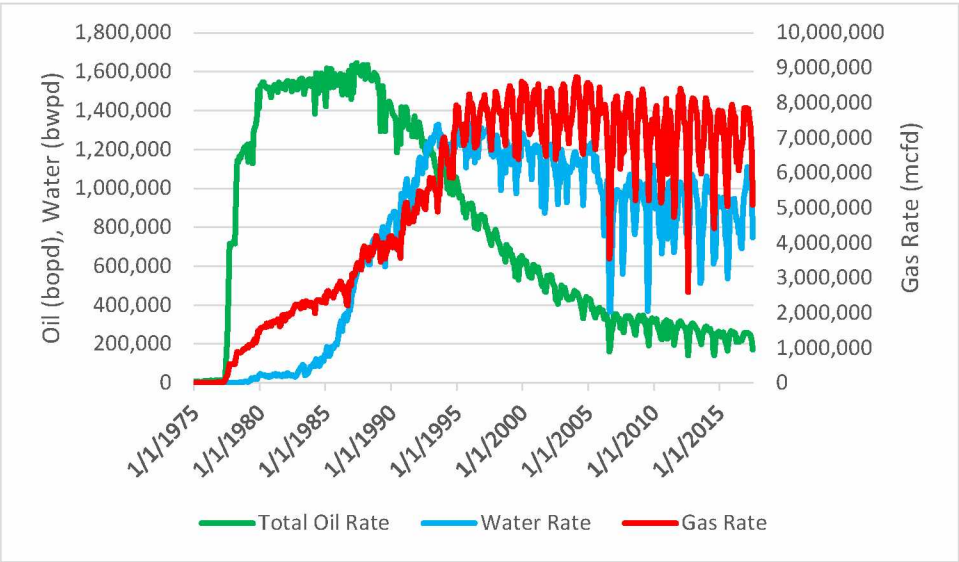


FIGURE 190: PRUDHOE BAY FIELD PRODUCTION





FIGURE 191: PRUDHOE BAY PRODUCTION AND ACTIVE WELL COUNT

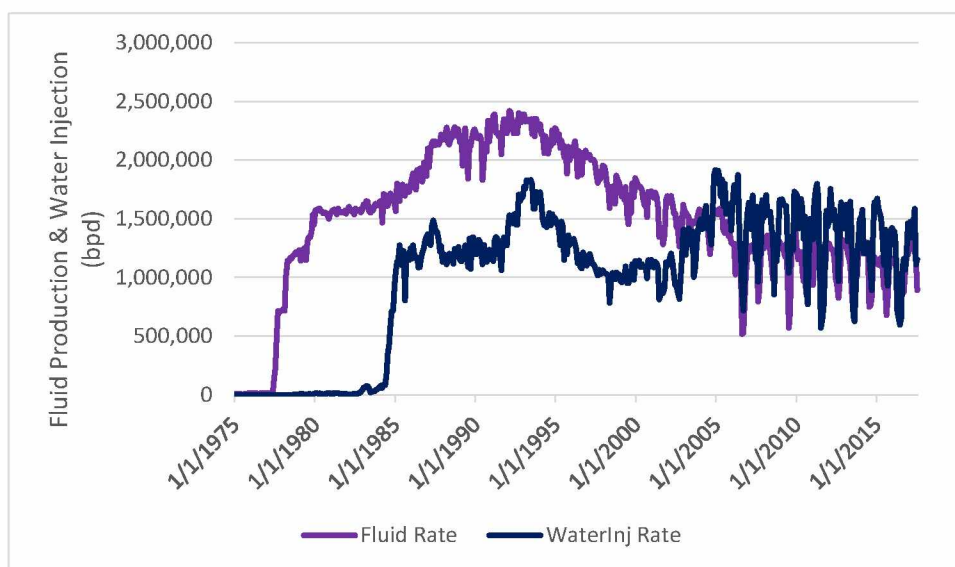


FIGURE 192: PRUDHOE BAY FLUID PRODUCTION AND WATER INJECTION RATE



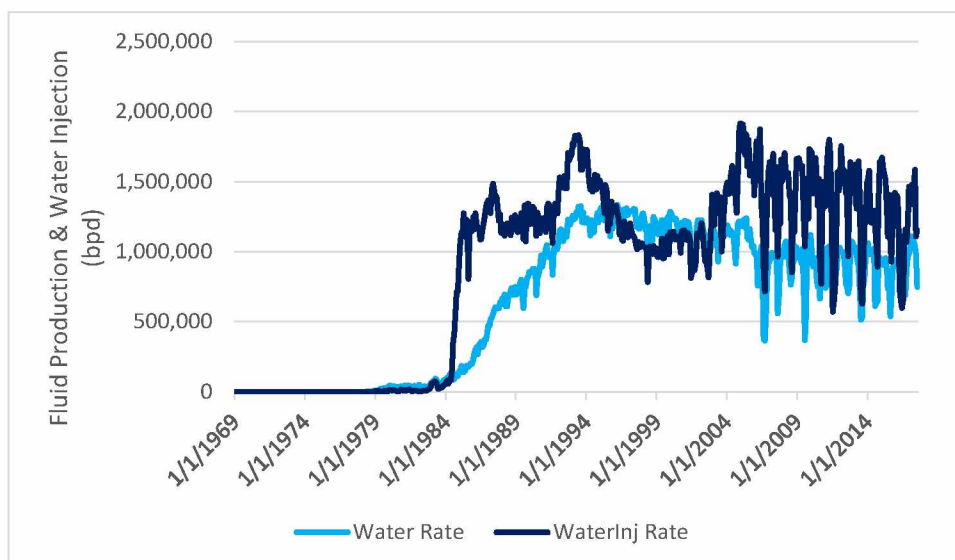


FIGURE 193: PRUDHOE BAY WATER PRODUCTION AND INJECTION RATE

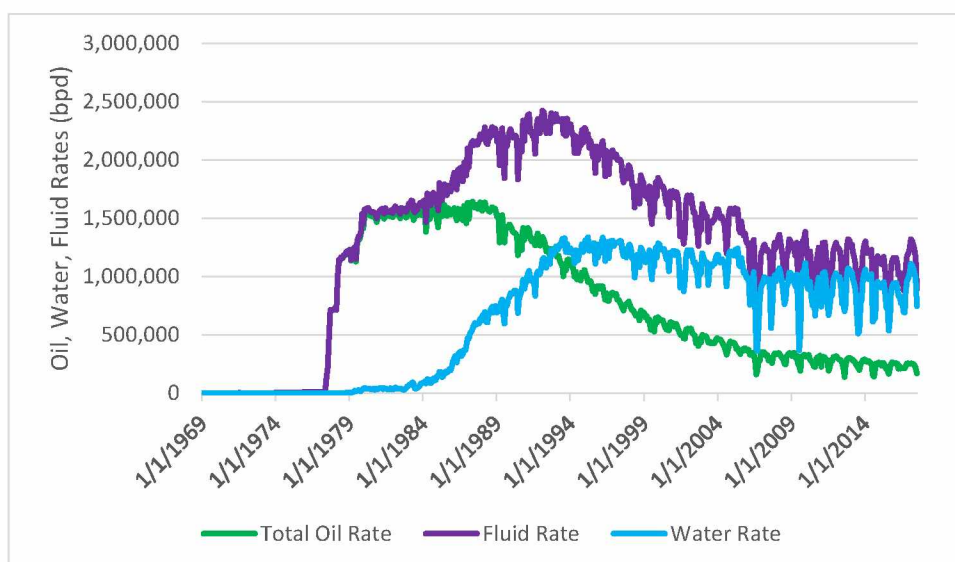


FIGURE 194: PRUDHOE BAY FLUID RATE PRODUCTION BY OIL AND WATER RATE

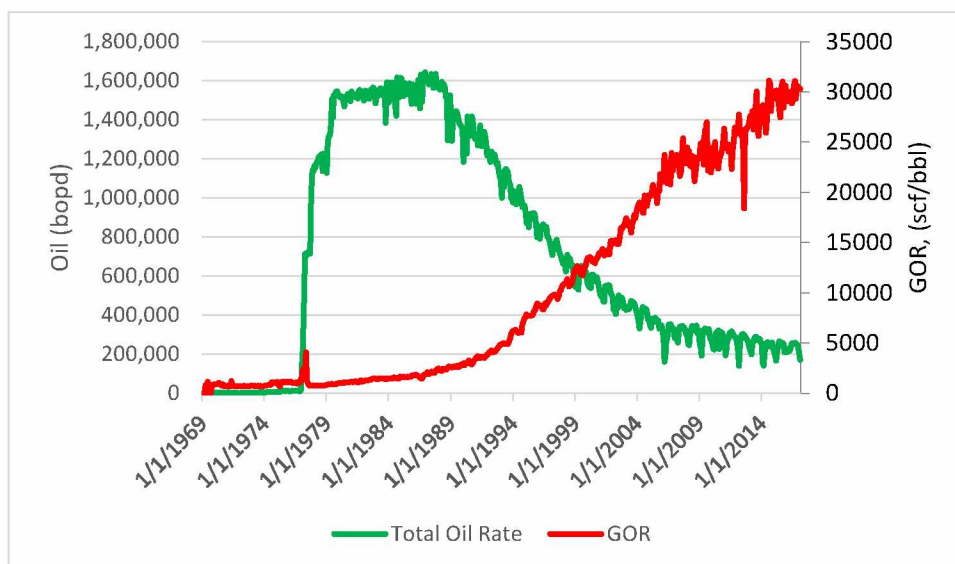


FIGURE 195: PRUDHOE BAY OIL PRODUCTION AND GAS OIL RATIO

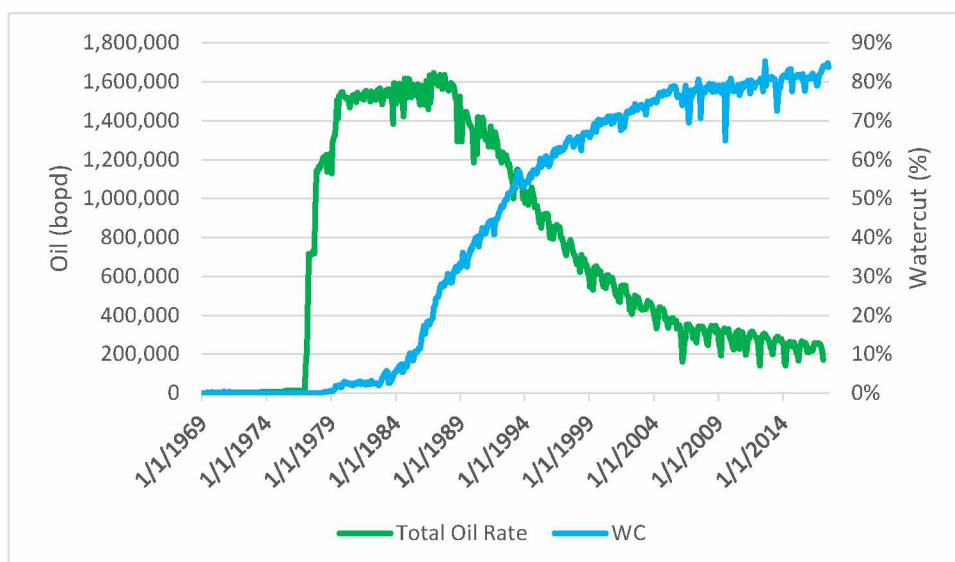


FIGURE 196: PRUDHOE BAY PRODUCTION AND WATERCUT

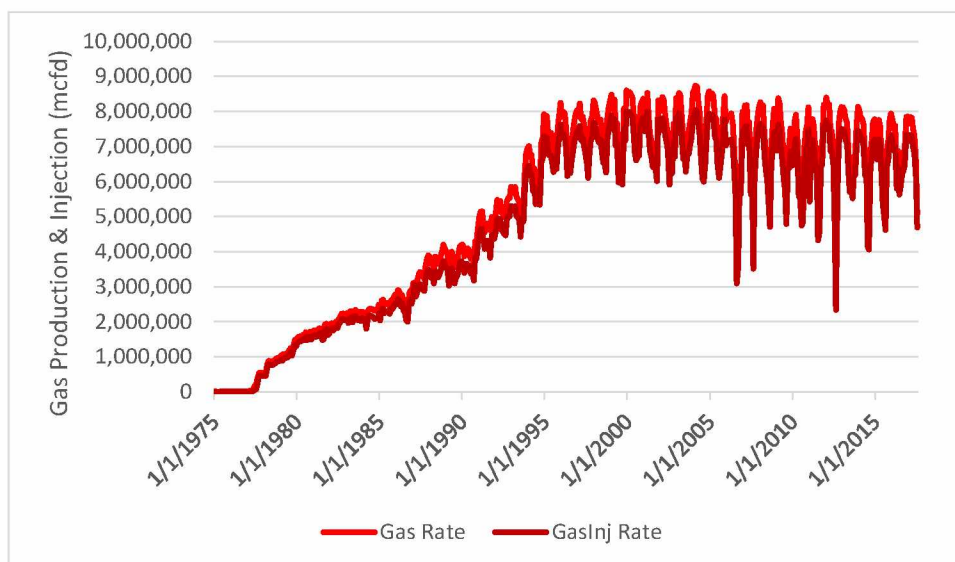


FIGURE 197: PRUDHOE BAY GAS PRODUCTION AND INJECTION

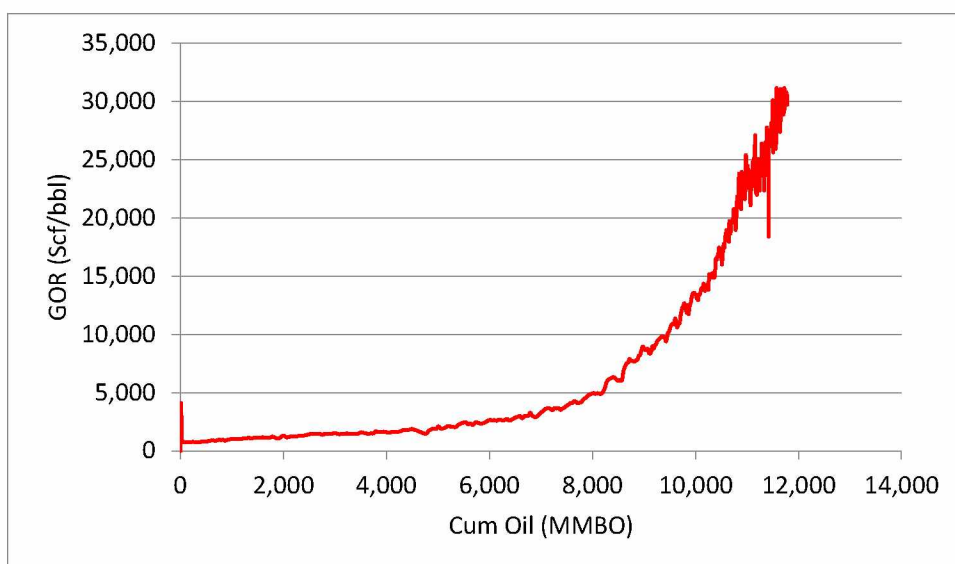


FIGURE 198: PRUDHOE BAY GAS OIL RATIO VS. CUM OIL

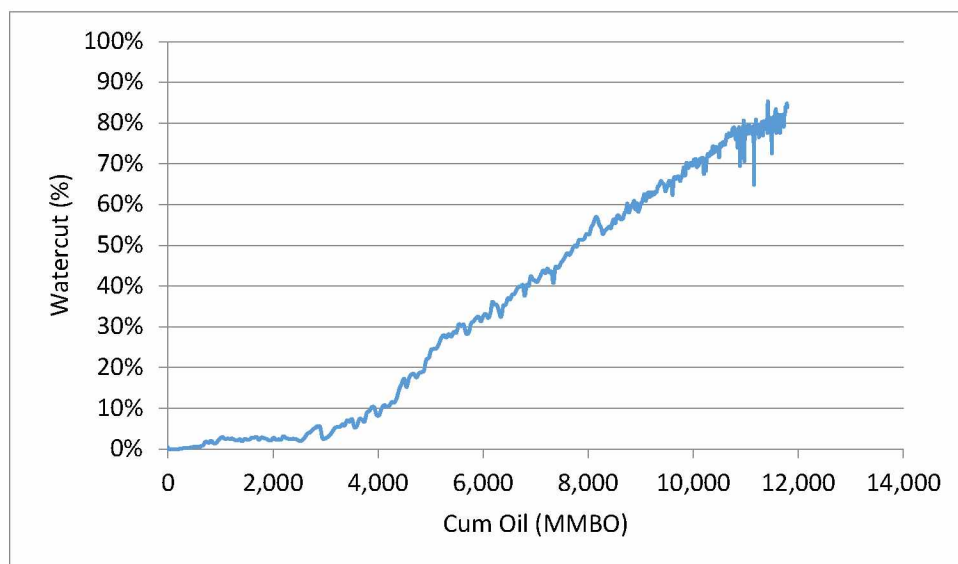


FIGURE 199: PRUDHOE BAY WATERCUT VS. CUM OIL

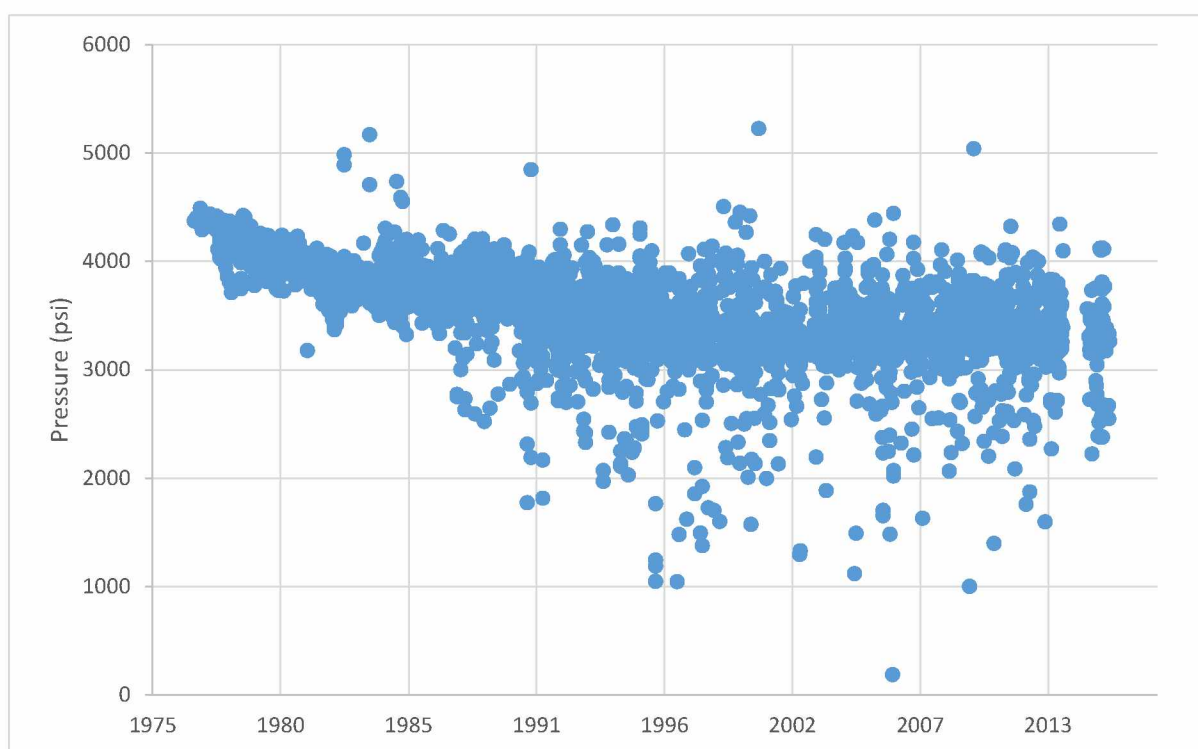


FIGURE 200: PRUDHOE BAY PRESSURES

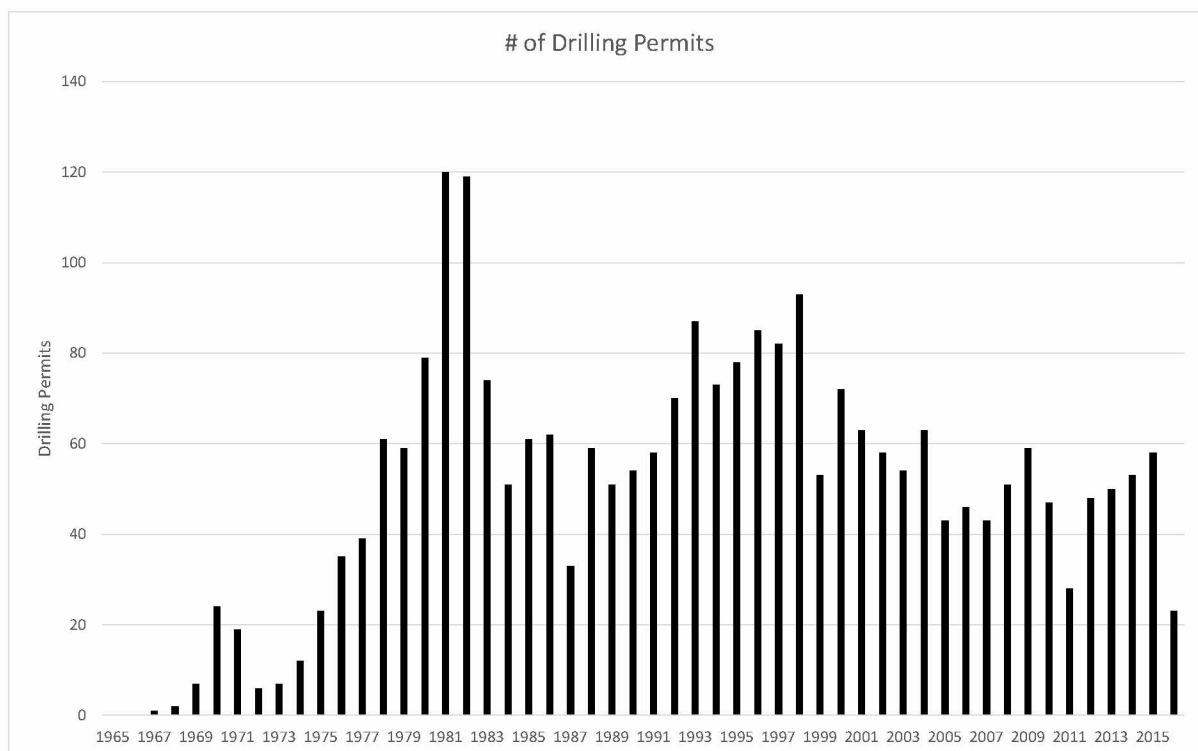


FIGURE 201: PRUDHOE BAY DRILLING PERMITS BY YEAR

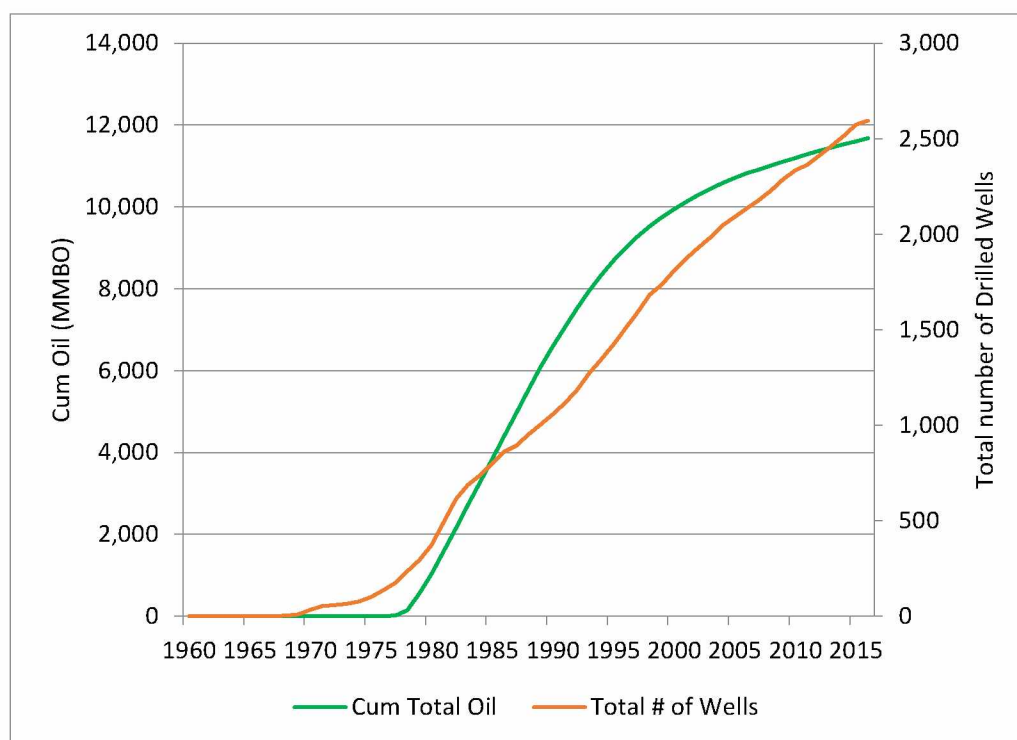


FIGURE 202: PRUDHOE BAY CUM OIL AND TOTAL WELLS DRILLED

Although over 2,500 wells have been drilled in Prudhoe Bay, less than 1,000 are active today. This is in part due to an active sidetrack campaign, where wells are redrilled to more favourable locations, but also due to aging wells, and facility constraints. A distribution of parent bore versus sidetrack number for active wells can be seen in Figure 210. This continual drilling over the last 50 years as seen in Figure 201, has resulted in a lower cum oil per well, however has contributed to a higher recovery. Figure 203 shows dynamically how the cum oil

per well has decreased with time since the early 1990s as the new wells increase the overall well count, however produce less than the average historic well. Figure 206 and Figure 207 show the decreasing average cum oil by drilled year. When it is considered by development phase, the initial development wells, or those that were drilled before production and during ramp-up, are only 9% of total wells drilled, however contribute 38% of the total production. The wells drilled during plateau make up 25% of the wells drilled, and 43% of the total production. The late life wells, those which were drilled after the start of Prudhoe Bay decline, make up 66% of the wells drilled, but only 19% of the total production. Although these wells have had less time online to produce large volumes, they also are unlikely to produce the volumes of the earlier wells due to dynamic changes in the reservoir.

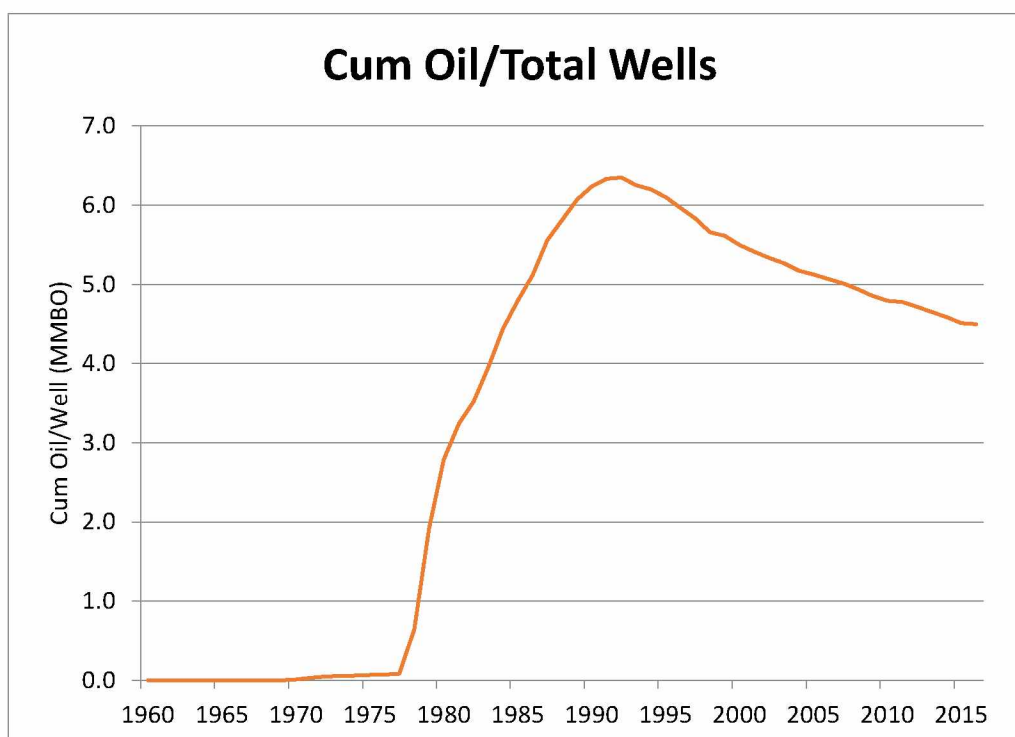


FIGURE 203: PRUDHOE BAY CUM OIL/TOTAL WELLS BY YEAR

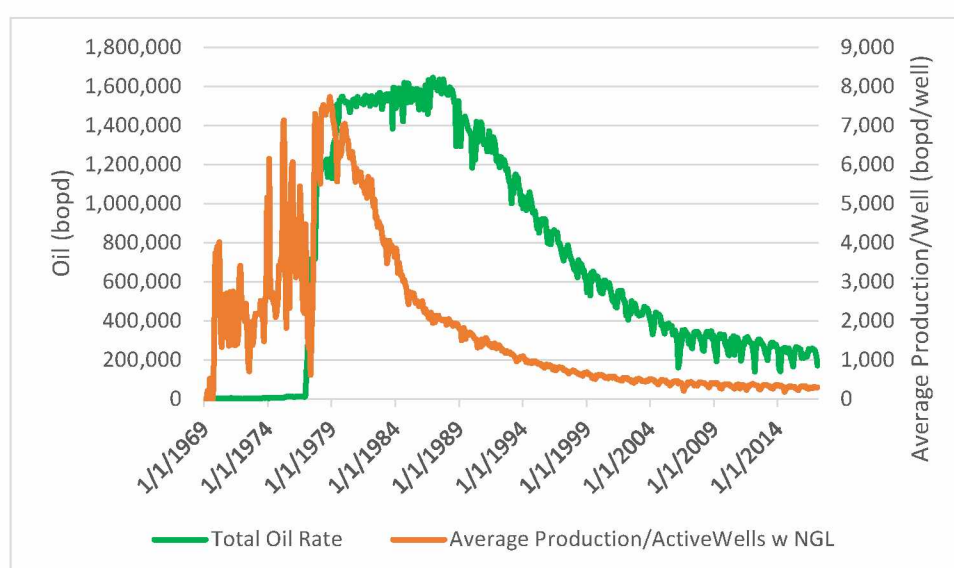


FIGURE 204: PRUDHOE BAY AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL)



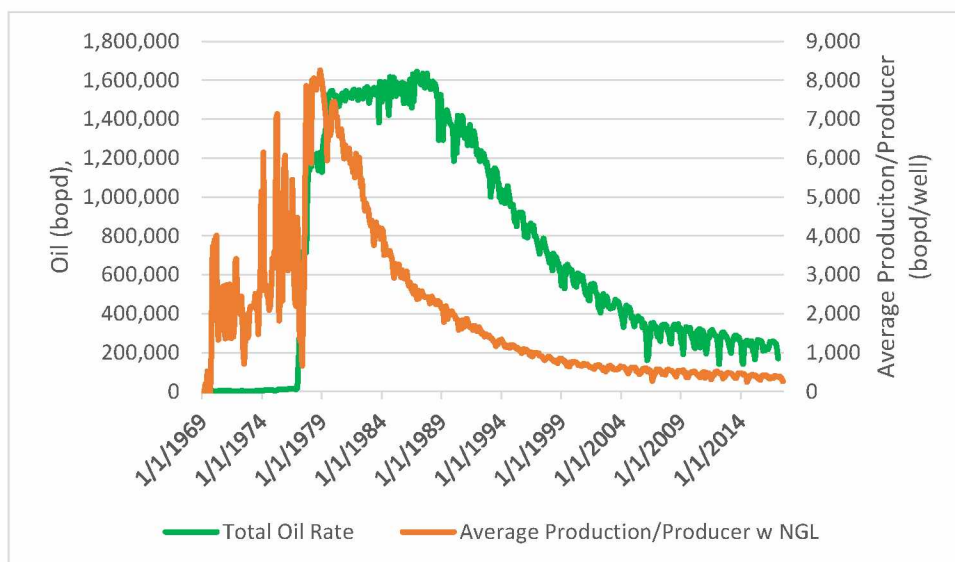


FIGURE 205: PRUDHOE BAY AVERAGE PRODUCTION/PRODUCER (BOPD/WELL)

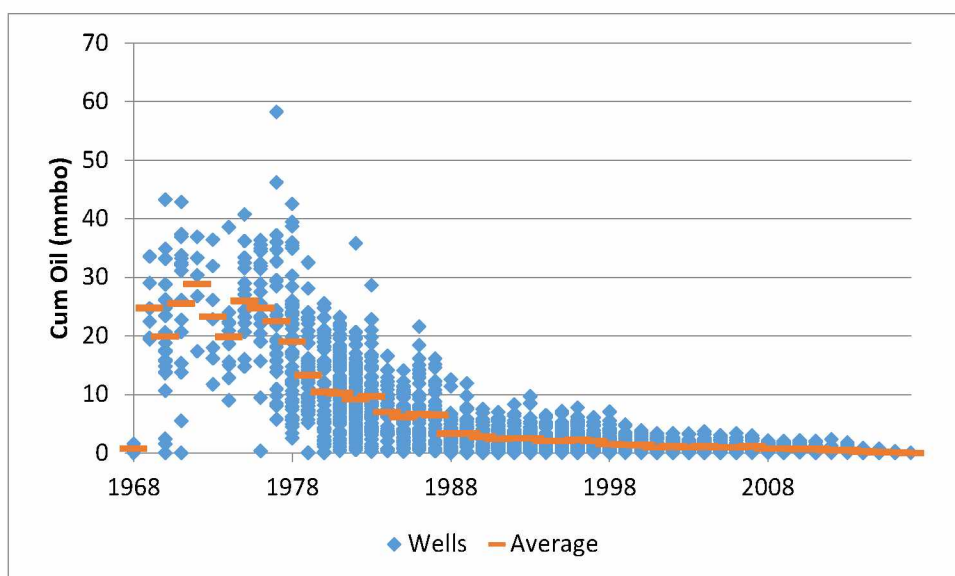


FIGURE 206: PRUDHOE BAY WELL CUM OIL BY PERMIT YEAR

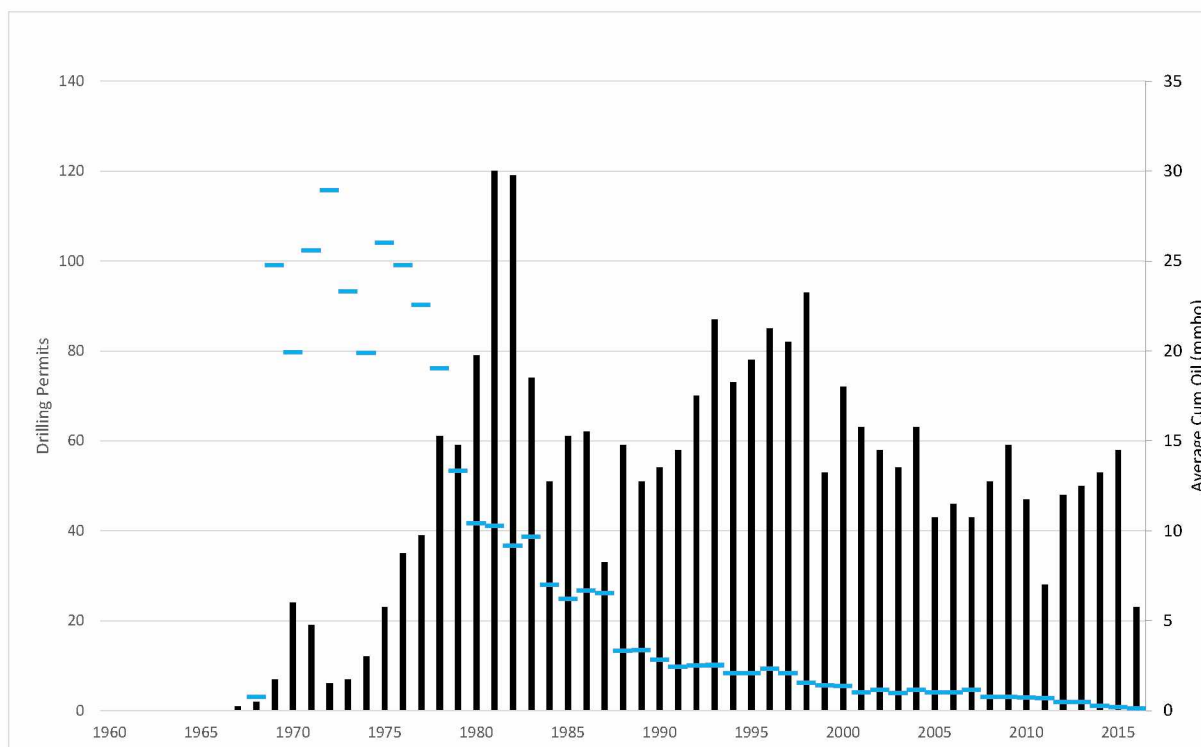


FIGURE 207: PRUDHOE BAY NUMBER OF DRILLING PERMITS AND AVERAGE CUM OIL TO DATE OF ASSOCIATED WELLS BY YEAR

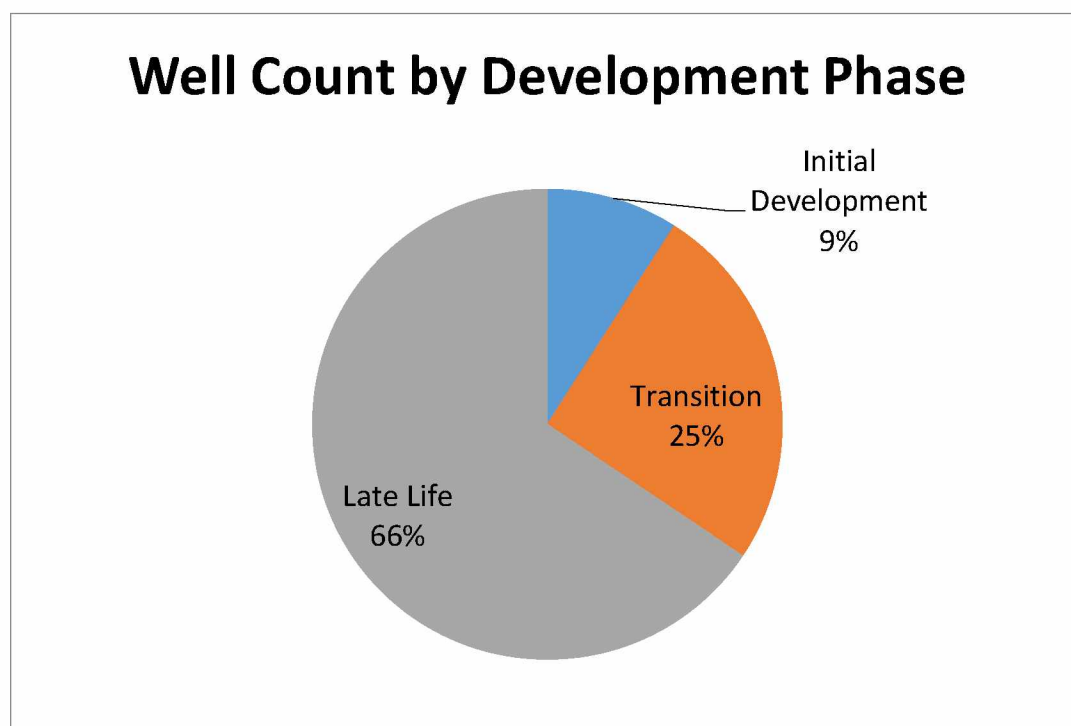


FIGURE 208: PRUDHOE BAY WELL COUNT BY DEVELOPMENT PHASE

## Cum Oil by Development Phase

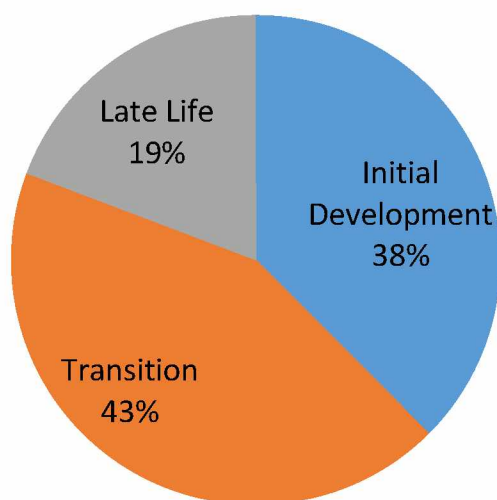


FIGURE 209: PRUDHOE OIL CUM OIL BY DEVELOPMENT PHASE

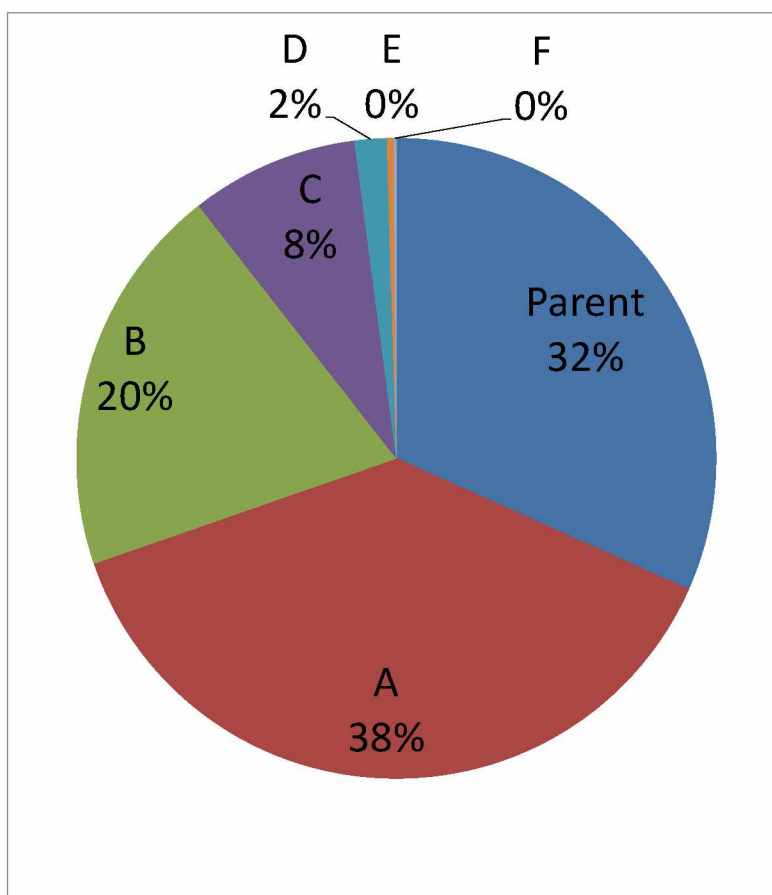


FIGURE 210: DISTRIBUTION OF 2016 PRUDHOE BAY ACTIVE WELLS BY SIDETRACK BORE

## 15.9. POINT MCINTYRE

The Point McIntyre field, commonly referred to as Pt. Mac, is located to the north of Prudhoe Bay and produces from two drillsites, P1 and P2, sometimes called PM1 and PM2. It was discovered in 1988 produces from the Kuparuk formation. The field has two main producing sections, a gas cap to the south on the other side of a terrace fault, and a waterflood in the north, which is developed in inverted nine spot patterns and has an active MWAG flood. Pt. Mac produces to the Lisburne Production Center (LPC), which it shares with the other fields within GPMA. Production began in 1993 and peaked over 170,000 bopd. The field has produced 477 million barrels of oil and is producing 12,000 bopd from 40 wells.

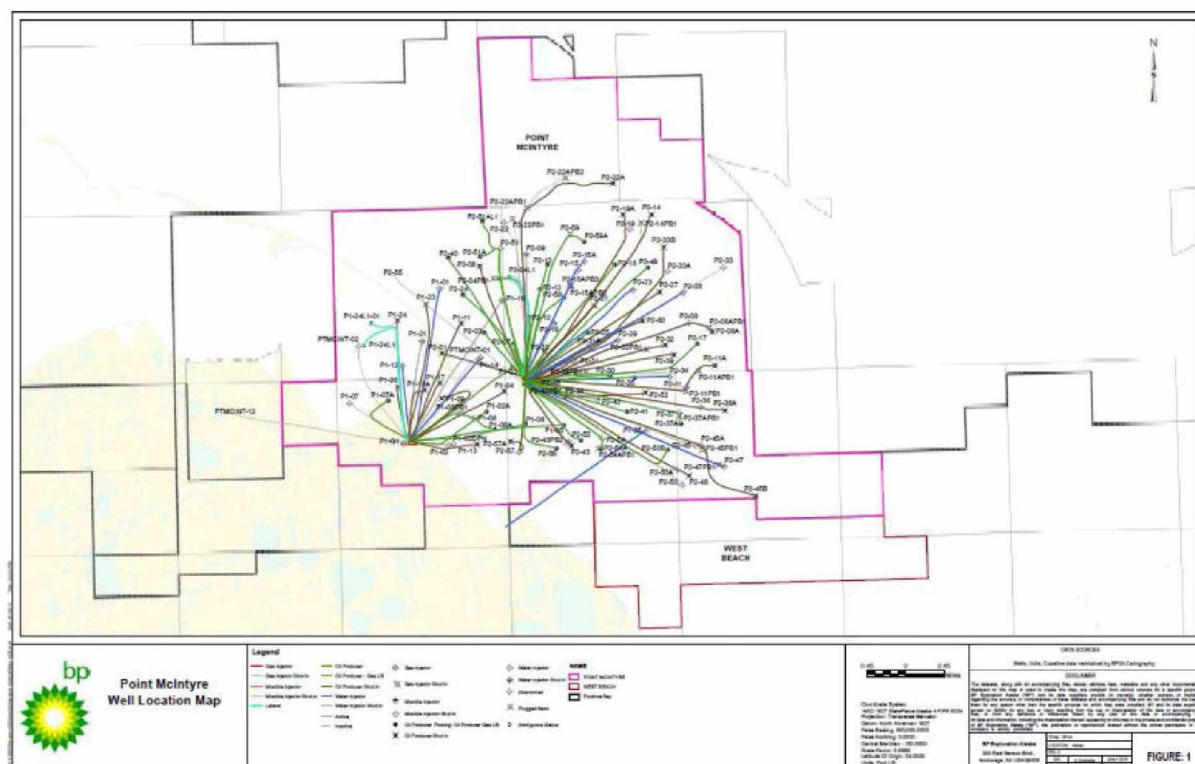


FIGURE 211: PT. MCINTYRE WELL LOCATION MAP (BP EXPLORATION (ALASKA) INC, 2017)

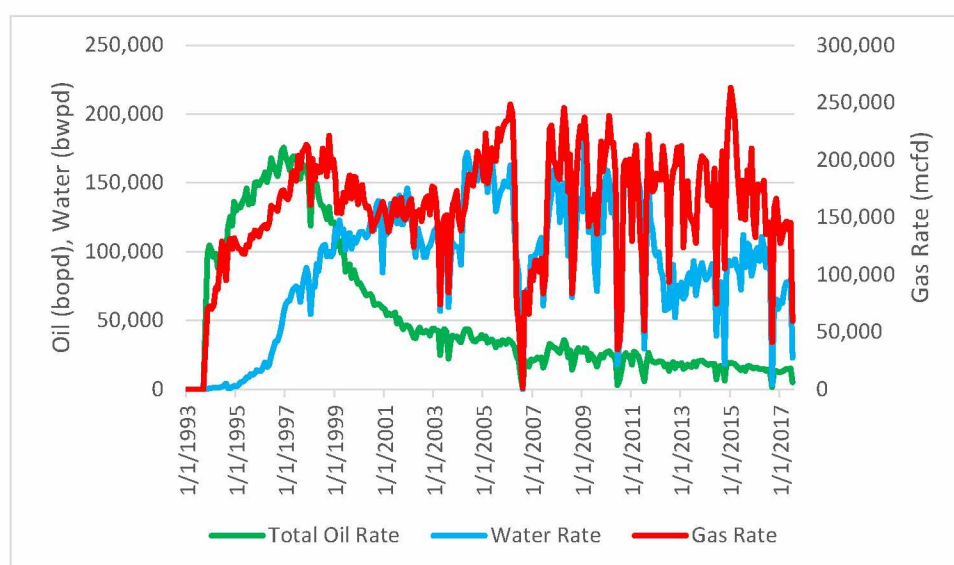


FIGURE 212: PT. MCINTYRE FIELD PRODUCTION



FIGURE 213: PT. MCINTYRE PRODUCTION AND ACTIVE WELL COUNT

### 15.10. WEST BEACH

The West Beach Field is located in the Greater Pt. McIntyre Area within the Prudhoe Bay Unit. The field was discovered in 1976 with the West Beach State 3 well. It produces from the Kuparuk formation and has been delineated by eleven penetrations (seven wells and four sidetracks) is comprised currently comprised of WB-04, WB-05B, and an injector WB-06 (BP Exploration (Alaska) Inc, 2017). 92% of field production has been from WB-04, and has been predominately primary depletion. WB-06 was converted from a producer to a water injector and injected from 2001-2003, however very little production occurred during or since as the field has been largely shut in. Water was sourced from the nearby Prince Creek source water well WB-07. The injector WB-06 is inoperable due to annular communication and WB-04, the predominant producer, showed breakthrough 4 months from injection start-up. The field is currently shut-in and requires pipeline inspections to be brought back online. The area was covered in a 2014/2015 seismic survey; however, the area faces challenges due to fluid uncertainty (BP Exploration (Alaska) Inc., 2017).

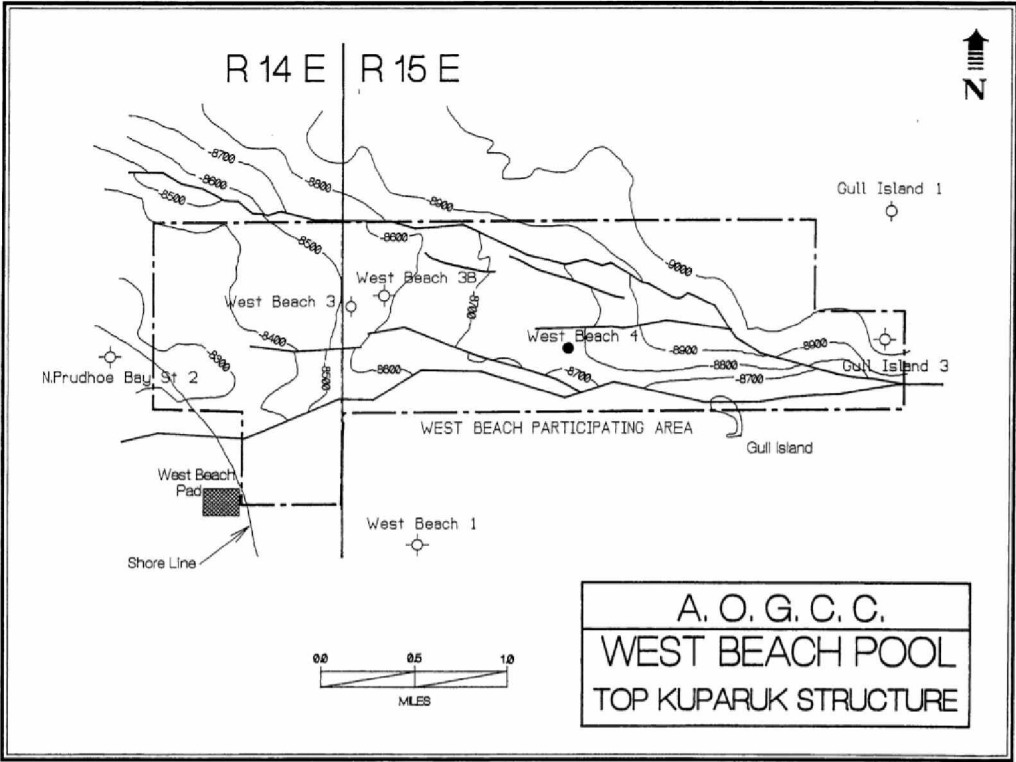


FIGURE 214: WEST BEACH STRUCTURE MAP (AOGCC, 2000)

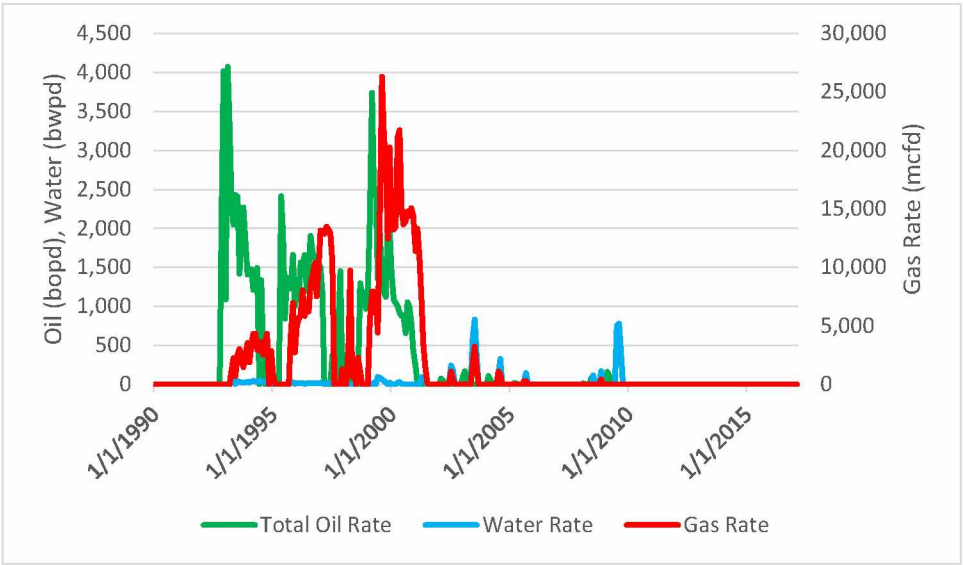


FIGURE 215: WEST BEACH PRODUCTION



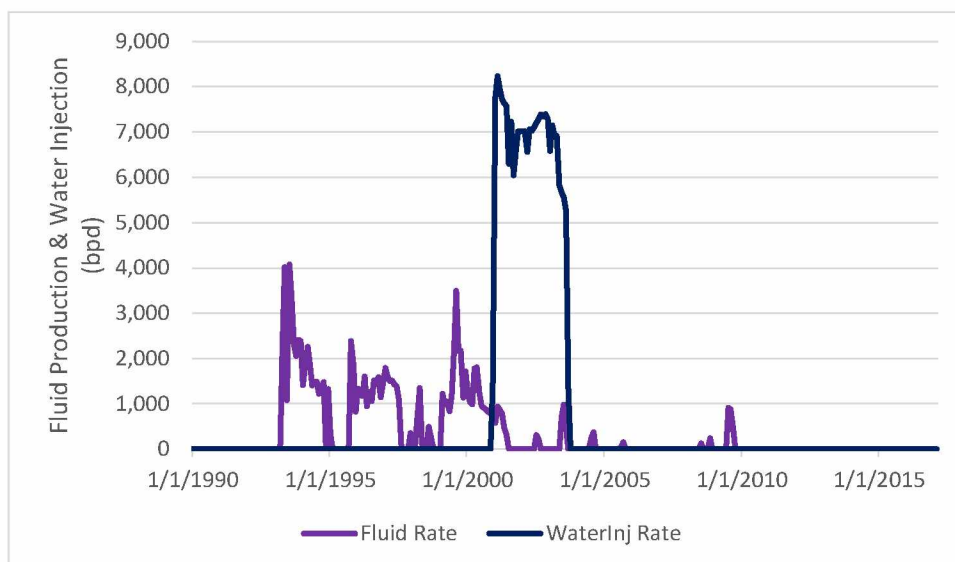


FIGURE 216: WEST BEACH PRODUCTION AND INJECTION

### 15.11. PUT RIVER

The Put River field is a small accumulation overlying Prudhoe Bay in the Put River formation and produced from DS2. It consists of two producers, 02-23A and 02-27A and an injector 01-08A. The field has produced 3 million barrels of oil to date, peaking at 3,000 bopd.

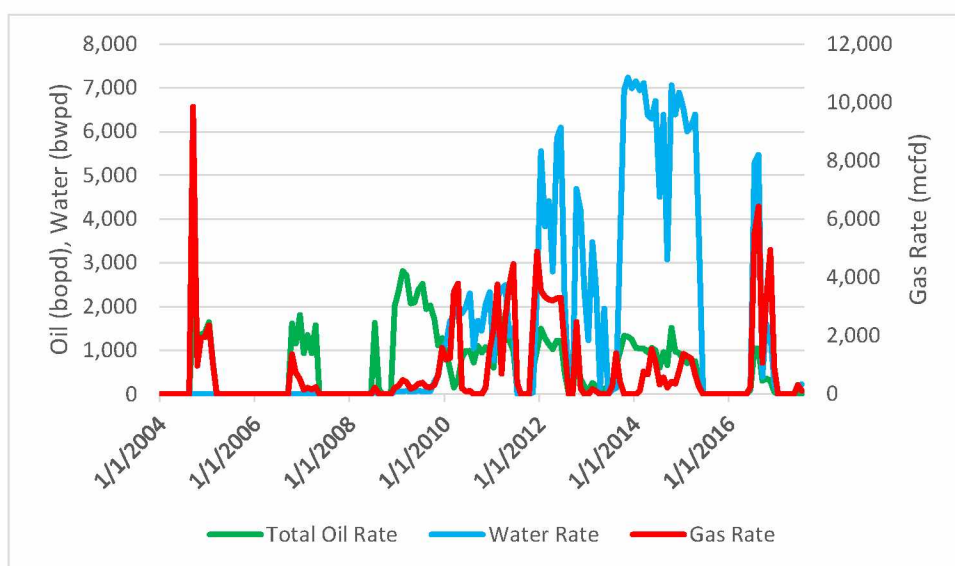


FIGURE 217: PUT RIVER FIELD PRODUCTION

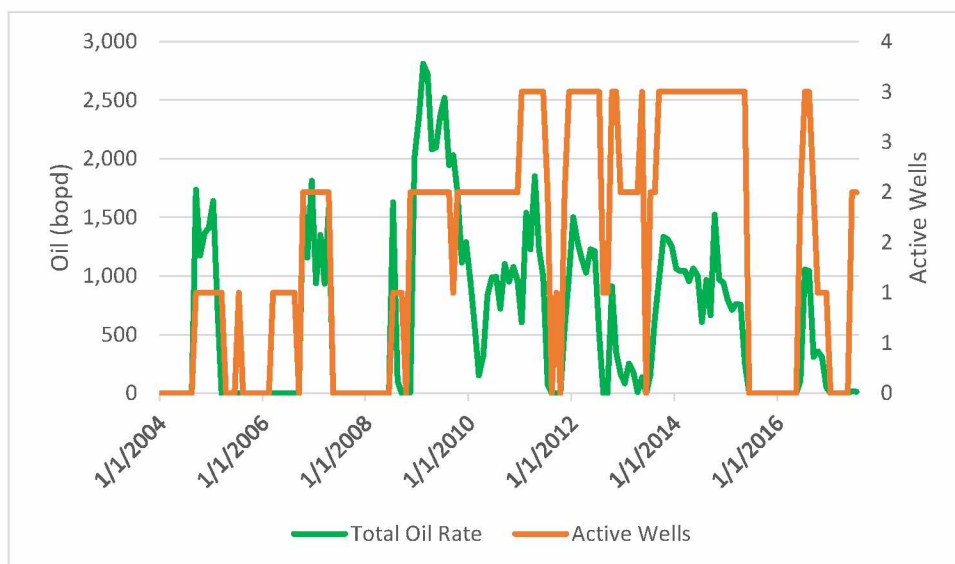


FIGURE 218: PUT RIVER PRODUCTION AND ACTIVE WELL COUNT

## 16. POINT THOMSON

The Point Thomson field located to the west of ANWR and produces from the Thomson sands. Although originally discovered in 1977, production did not begin until 2016. The field is operated by ExxonMobil and has suffered from facility problems. It has produced a half million barrels and has three active wells.

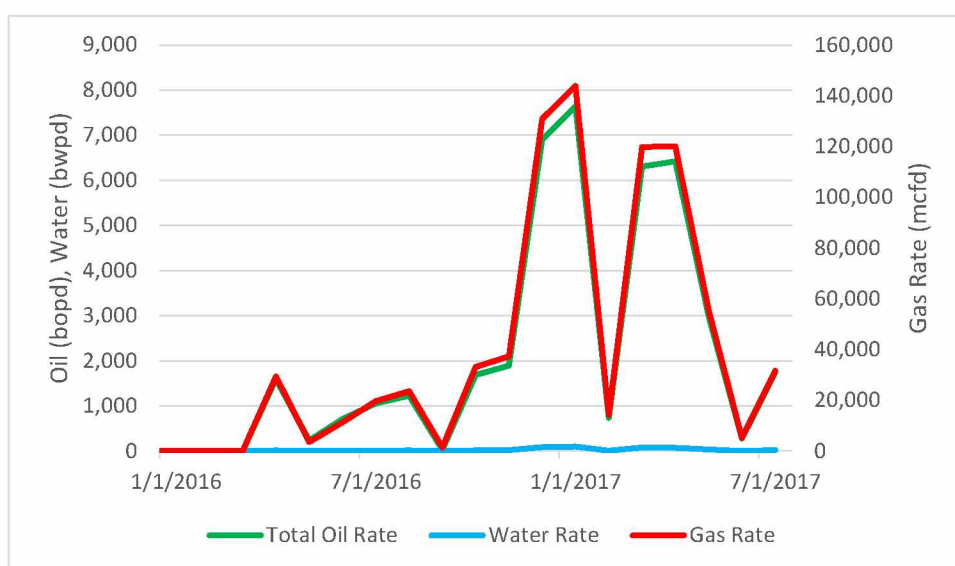


FIGURE 219: POINT THOMSON FIELD PRODUCTION

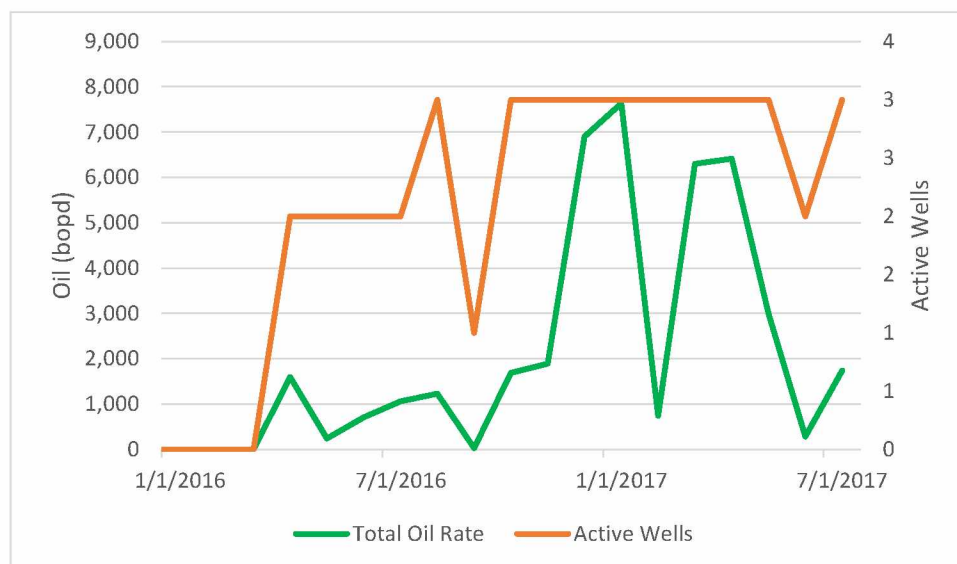


FIGURE 220: POINT THOMSON PRODUCTION AND ACTIVE WELL COUNT

## 17. CURRENT EXPLORATION

There has been a lot of recent exploration activity on the North Slope in the last 5-10 years, particularly in the Western North Slope near or in NPRA. Many of these prospects are relatively immature in terms of their understanding of size and deliverability, and actual development profiles will likely vary widely compared to current anticipated numbers for the projects that will be advanced. For this study the owners' projections were honored, though commentary on the feasibility of their profiles for some fields was added. Although there are several large new finds on the North Slope, some of these developments have been in progress for several years and have struggled with remoteness or marginal economics.

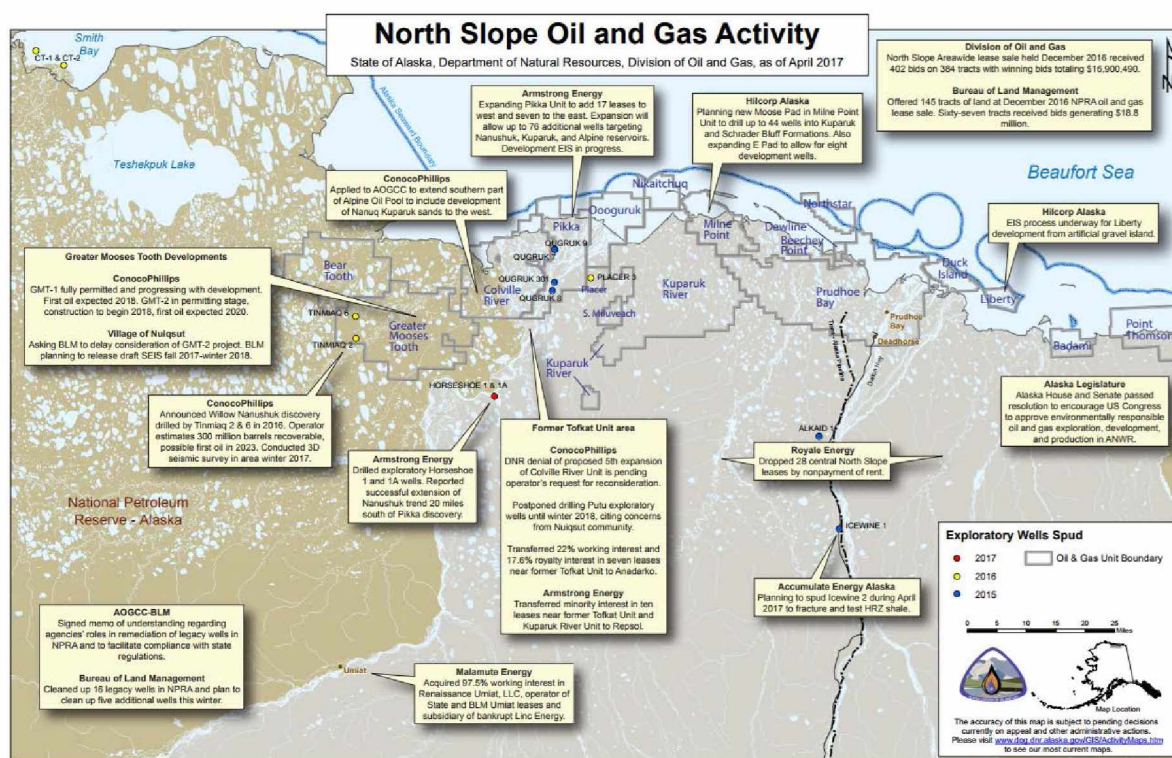


FIGURE 221: NORTH SLOPE OIL AND GAS ACTIVITY MAP (ALASKA DEPARTMENT OF NATURAL RESOURCES, DOG, 2017)



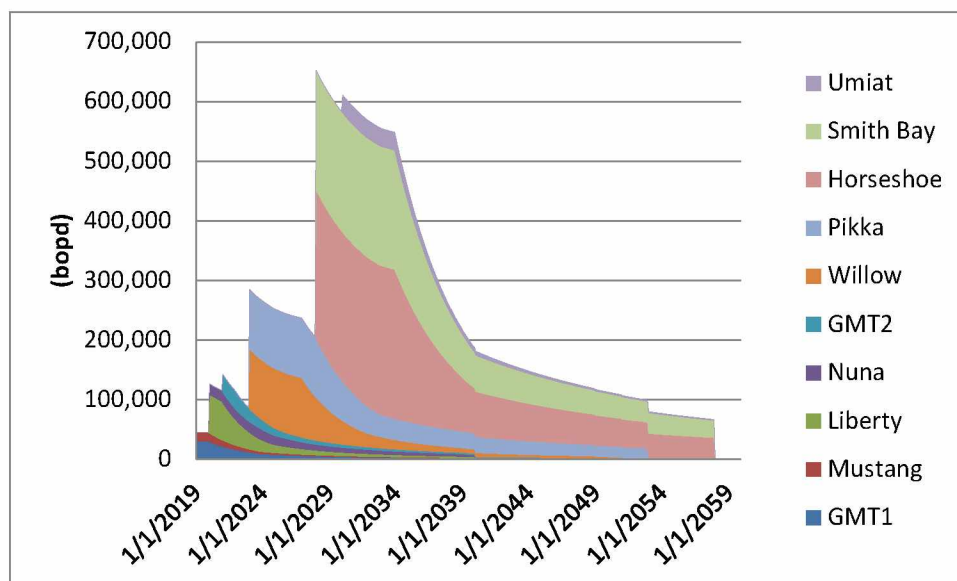


FIGURE 222: COMBINED HYPOTHETICAL PROFILES OF CURRENT EXPLORATION PROSPECTS

### 17.1. MUSTANG

The Mustang Field is in the Southern Miluvecch Unit and is operated by Brooks Range Petroleum. The field will produce from Kuparuk “C” and “A” sands and is expected to consist of up to 9 production wells and 17 Injection wells. There are 24.7 million barrels of proved oil reserves with probable and possible reserves of 44-51 million barrels (Bailey, Brooks Range’s Mustang Development Moving Forward Again After Recent Hiatus, 2016). This is about a million barrels per well, about 2.75 million barrels per producer, and is conservative compared to other Kuparuk formation fields. This Producer:Injector ratio is also much lower than the average Kuparuk formation field, as they most are between 1.25-2. Although previously was anticipated to come on in 2017, the current development plan has a dedicated facility coming online in December 2018, with peak capacity at 15,000 bopd (Brooks Range Petroleum Corporation, 2017). Some of the development has been paid for with loans through AIDEA who provided a \$20 million loan for the road and pad and \$50 million dollars in financing for the facility (ADEA, 2017).

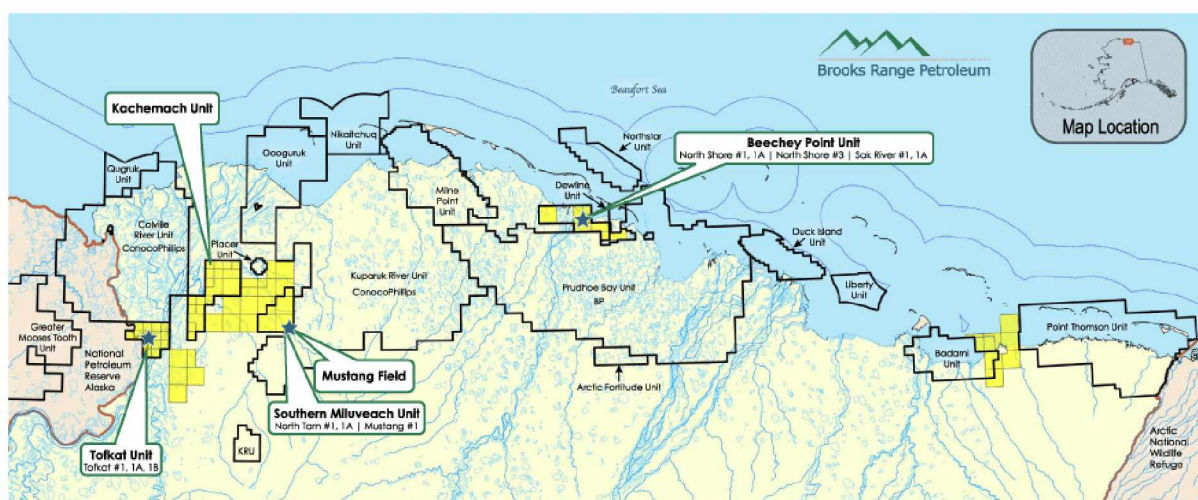


FIGURE 223: MAP OF BROOKS RANGE PETROLEUM ASSETS (BROOKS RANGE PETROLEUM, 2011)

## North Tarn 1 – Mud Log

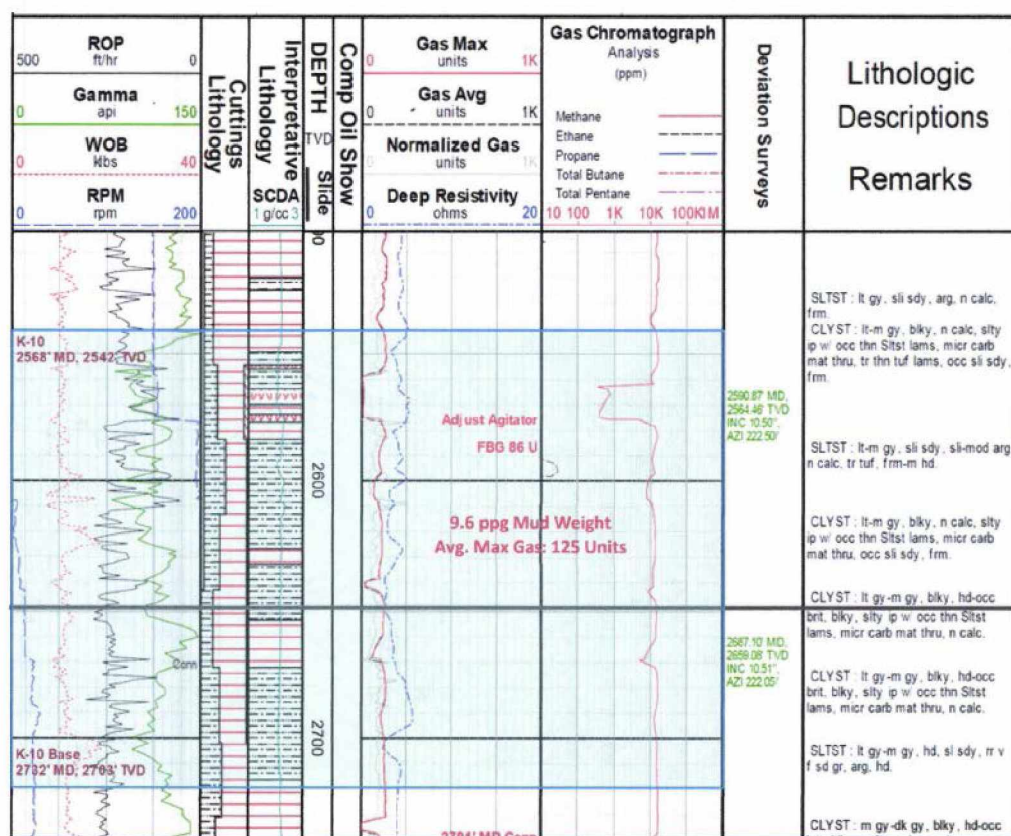


FIGURE 224: NORTH TARN 1 MUD LOG-K10 SAND (214-176 WELL FILE, 2017)

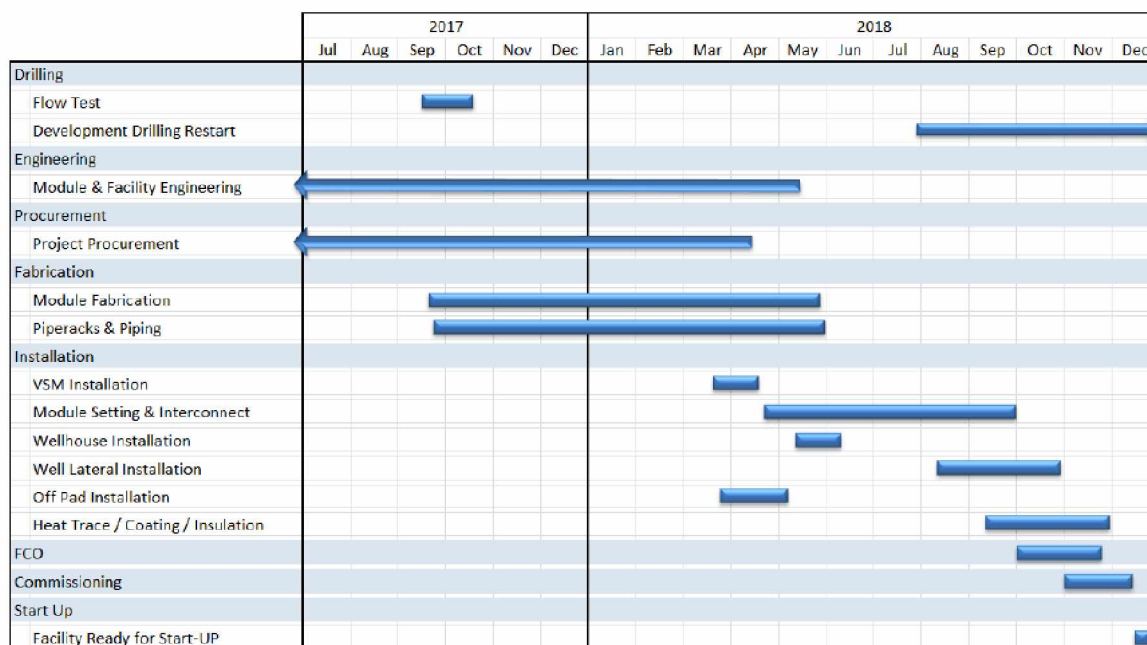


FIGURE 225: MUSTANG DEVELOPMENT SCHEDULE (BROOKS RANGE PETROLEUM CORPORATION, 2017)

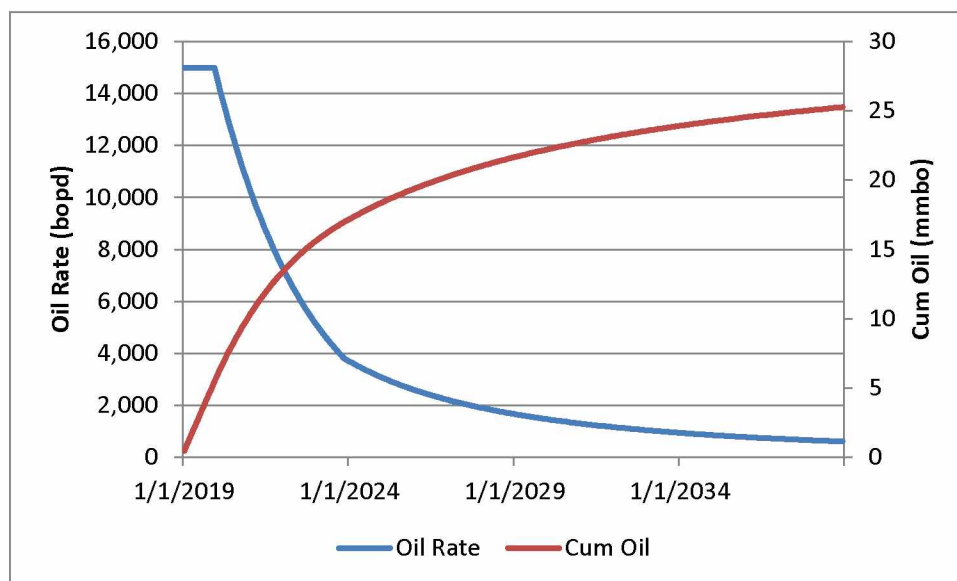


FIGURE 226: HYPOTHETICAL MUSTANG PRODUCTION FORECAST

## 17.2. PIKKA

### 17.2.1. EXPLORATION HISTORY

The Pikka unit as seen in Figure 227 lies east of the Colville River Unit and west of the Oooguruk and Kugaruk River units. When formed in 2015, it encompassed 63,304 acres and in 2016 was expanded by 14,440 acres (Alaska Division of Oil and Gas, 2016) as seen in Figure 228. This is to help encompass the play fairway as seen in Figure 233. The well Qugruk 1PH found 210 feet of Nuiqsut sands with good resistivity and a sidetrack was drilled with a production test. This well was had about a 1,000 feet of horizontal section and was hydraulically fractured with approximately 255,000 pounds of proppant (Alaska Division of Oil and Gas, 2016). Over four days this well flowed and average of 400-950 bopd of 25 degree API oil (Alaska Division of Oil and Gas, 2016). Qugruk 3 was later drilled showing about 200 feet of sand in the Nuiqsut with shows, but also potential in the Nanushuk formation, and 30.5 degree API oil was recovered from an MDT. Qugruk 3 was sidetracked and the Qugruk 3A well encountered 13 foot thick Kugaruk sands bearing oil, and oil shows were observed in the mud log through the Nanushuk, Alpine, and Kugaruk sands (Alaska Division of Oil and Gas, 2016). Qugruk 6 drilled an approximately 1,000 foot horizontal section in the Nechelek sand and was fracture stimulated with 271,000 pounds of proppant, and flowed at an average rate of 140 bopd of 36 degree API oil and a producing GOR of 11,400 scf/bbl. Qugruk 301 well was drilled with a 2,000 foot horizontal lateral in the Nanushuk formation and was able to achieve rates as high as 4,600 bopd (Alaska Division of Oil and Gas, 2016).



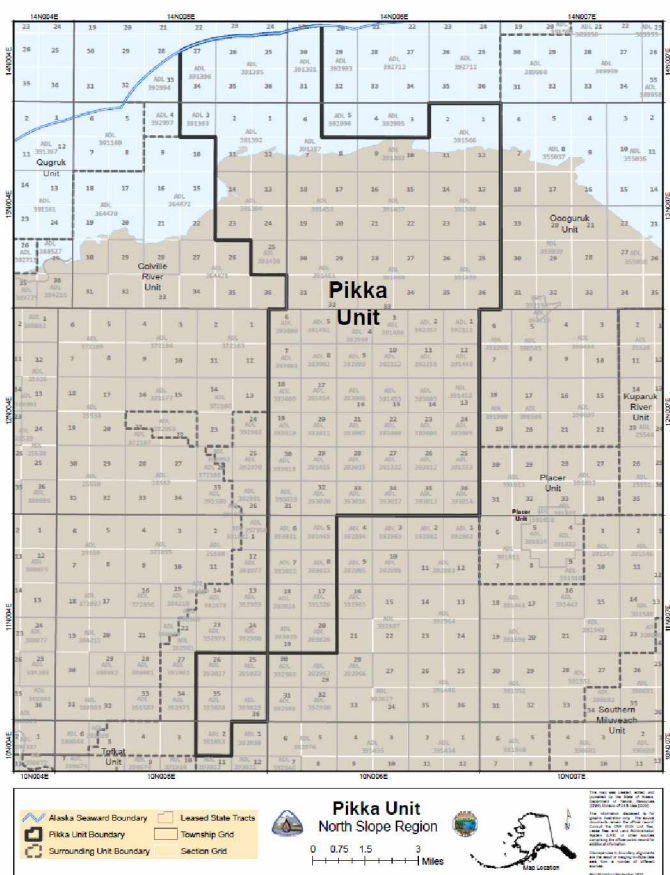


FIGURE 227: PIKKA UNIT MAP (ALASKA DEPARTMENT OF NATURAL RESOURCES, DOG, 2015)

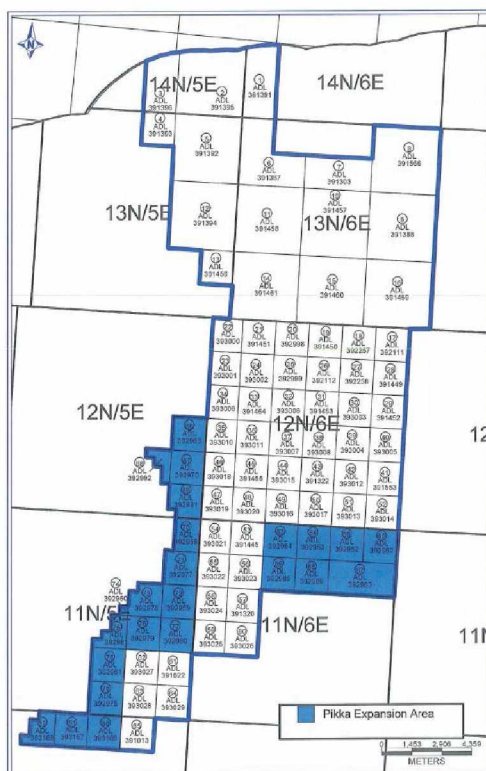


FIGURE 228: PIKKA UNIT EXPANSION AREA MAP (ALASKA DIVISION OF OIL AND GAS, 2016)

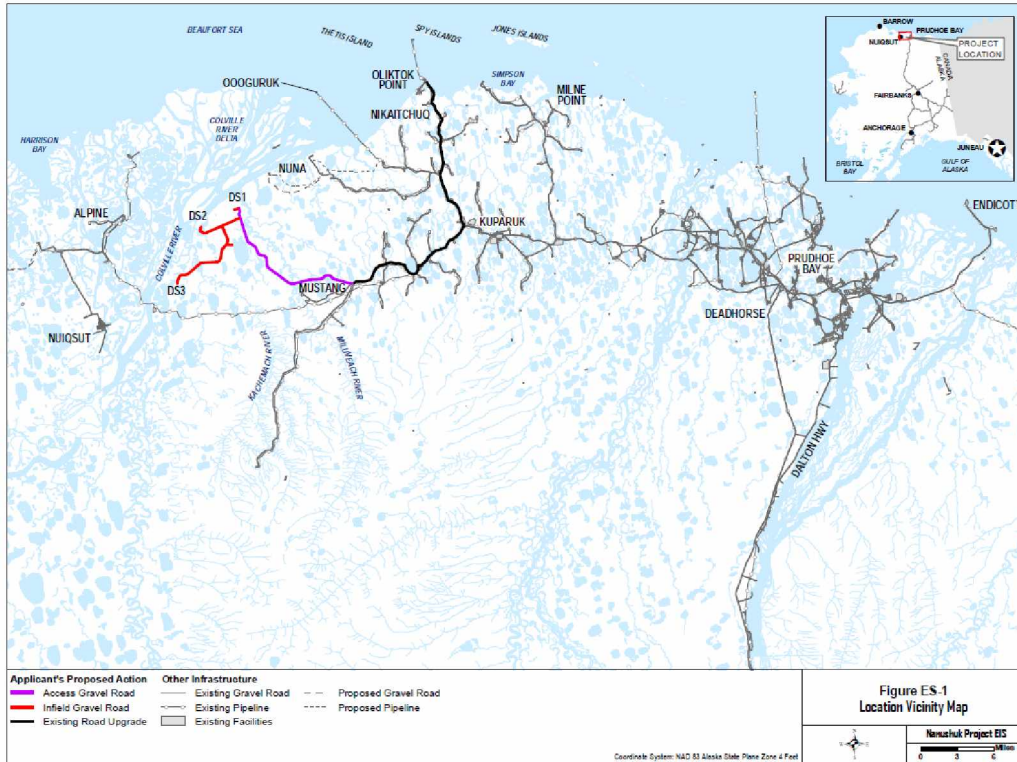


FIGURE 229: PIKKA PROPOSED DEVELOPMENT MAP (UNITED STATES ARMY CORPS OF ENGINEERS, 2017)

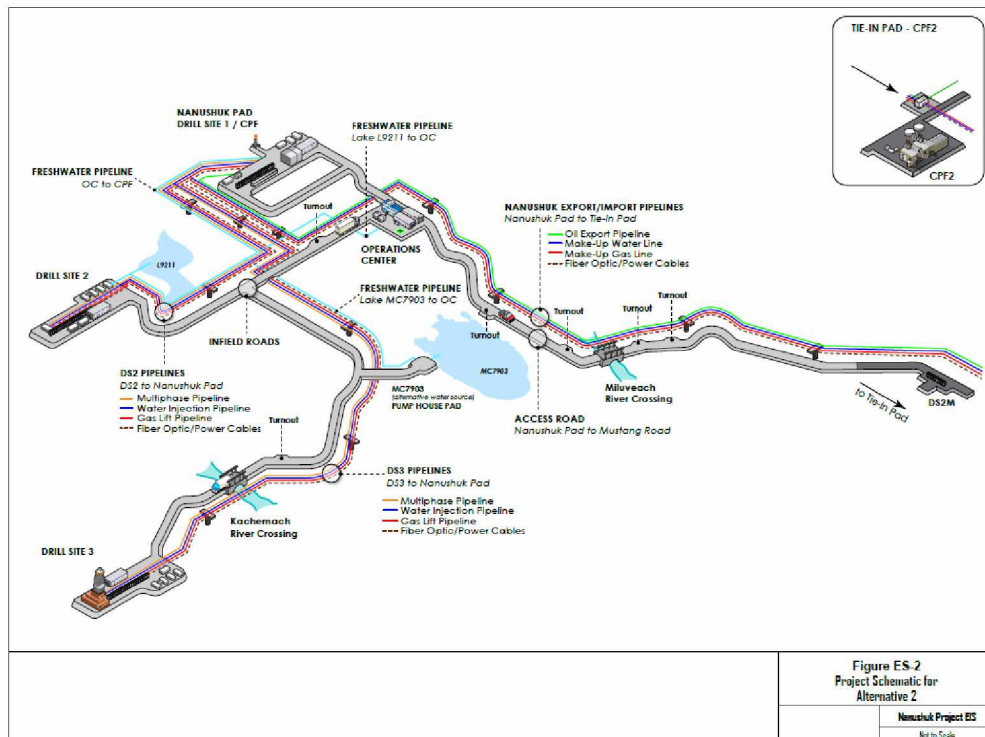


FIGURE 230: PIKKA SURFACE DEVELOPMENT SCHEMATIC (UNITED STATES ARMY CORPS OF ENGINEERS, 2017)

### 17.2.2. DEVELOPMENT

In November 2017, Oil Search acquired interest in the Pikka unit and operatorship from Armstrong for \$400 million, with to further increase their interest for an additional \$450 million (Oil Search Limited, 2017). The

Pikka phase 1 development is expected to consist of 60 producers and 60 injectors from three drill sites, have a dedicated processing facility and plateau between 80,000 to 120,000 bopd recovering 500 million barrels of oil with billions more in contingent reserves (Oil Search Limited, 2017). The field is expected to come online in 2023. This means the expectation is for the field to have a 1:1 Producer:Injector ratio and average 4.2 million barrels per well, 8.3 million barrels per producer. Comparative to other pools, this is the equivalent of an Alpine field production profile, but with about a 40% improved well performance, as Alpine currently has 166 (156 active) wells. This assumption is also more than twice as productive as the next best Brookian aged field, Tarn, which has produced about 1.5 million barrels per well out of the Seabee formation. Assuming Qugruk 3 is a representative well of the play, which has permeabilities of 1-17 mD, and is in a sand 200 feet thick, with the high API oil, based on trends seen in Figure 16 the field is likely to have an actual cum oil per well between 1.5-2 million barrels, less than half of what is anticipated. Figure 44, Figure 76, and Figure 206 demonstrate that the initial wells drilled are more productive than subsequent wells, creating unrealistic expectations if future wells are assumed to perform like previous wells. Additionally, Figure 17 shows that fields that if online wells are used as type curve analogs for field development, it overestimates the productivity per well on average by a factor of 2.

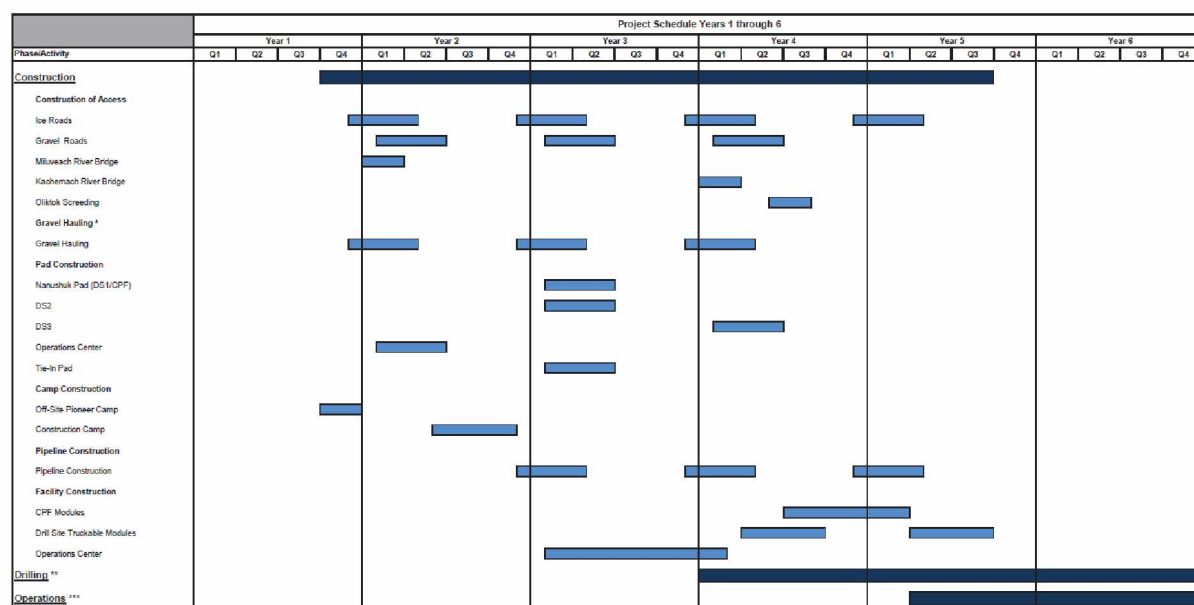


FIGURE 231: NANUSHUK PROJECT DEVELOPMENT SCHEDULE (UNITED STATES ARMY CORPS OF ENGINEERS, 2017)

Phase	Lease Category	Oil Search	AMERICAN	NGMT	REPSOL
Pre-transaction	Pikka Unit	-	38.25 %	12.75 %	49 %
	Horseshoe	-	56.25 %	18.75 %	25 %
	Exploration	-	56.25 %	18.75 %	25 %
	Hue Shale	-	100 %	-	-
Current transaction	Pikka Unit	25.5 %	19.125 %	6.375 %	49 %
	Horseshoe	37.5 %	28.125 %	9.375 %	25 %
	Exploration	25.5 %	37.125 %	12.375 %	25 %
	Hue Shale	37.5 %	62.5 %	-	-
Post OSH's option to acquire balance	Pikka Unit	51 %	-	-	49 %
	Horseshoe	75 %	-	-	25 %
	Exploration	51 %	18 %	6 %	25 %
	Hue Shale	75 %	25 %	-	-

FIGURE 232: PIKKA OWNERSHIP AFTER OIL SEARCH ACQUISITION (OIL SEARCH LIMITED, 2017)



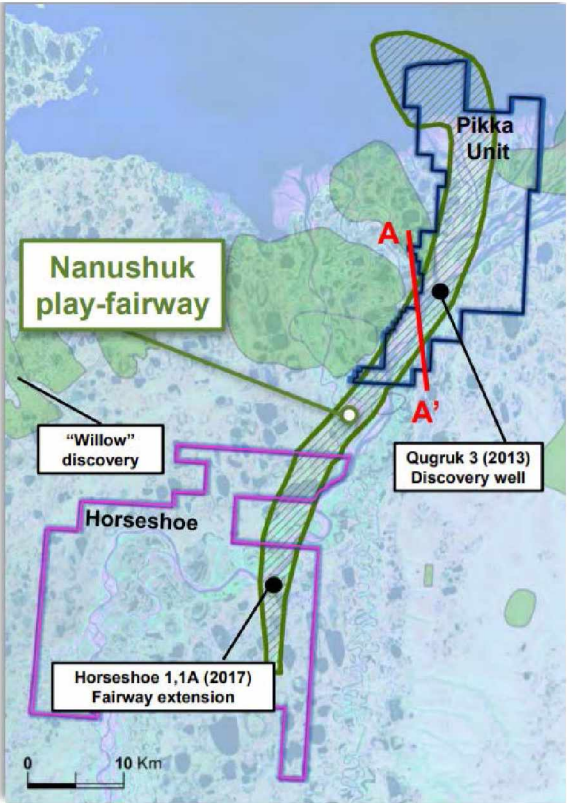


FIGURE 233: NANUSHUK PLAY FAIRWAY IN PIKKA AND HORSESHOE UNITS (OIL SEARCH LIMITED, 2017)

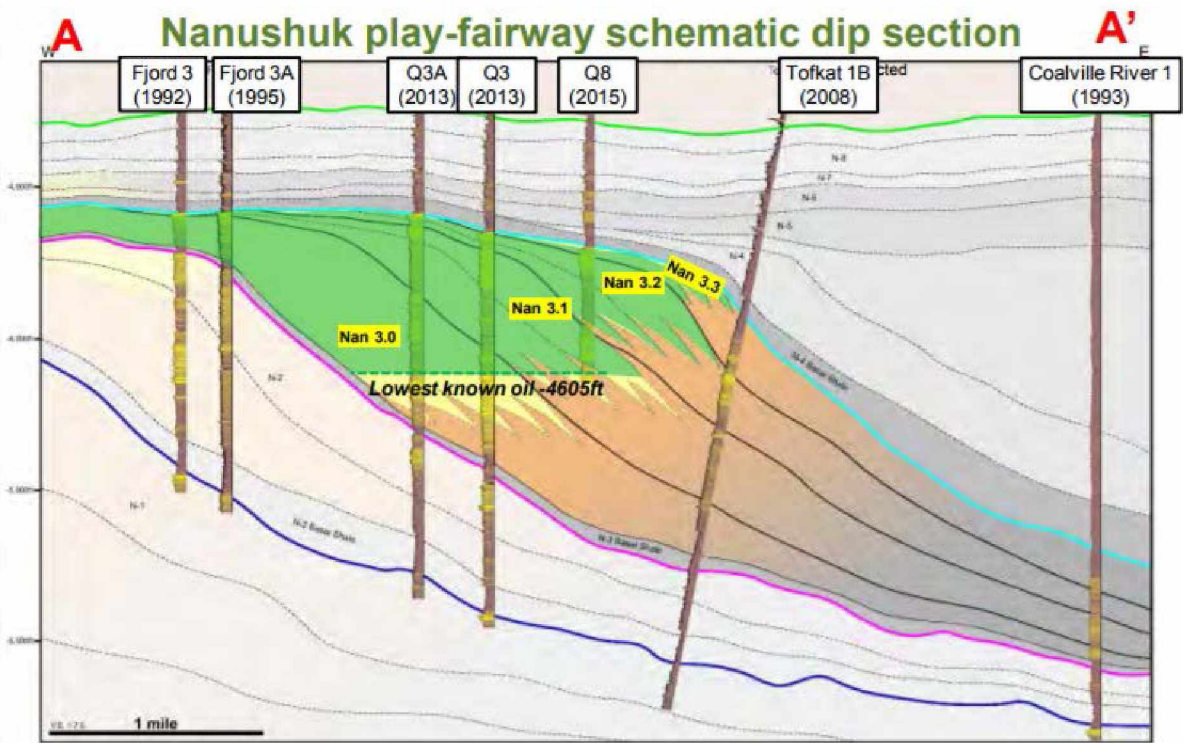


FIGURE 234: NANUSHUK CROSS SECTION IN PIKKA UNIT (OIL SEARCH LIMITED, 2017)

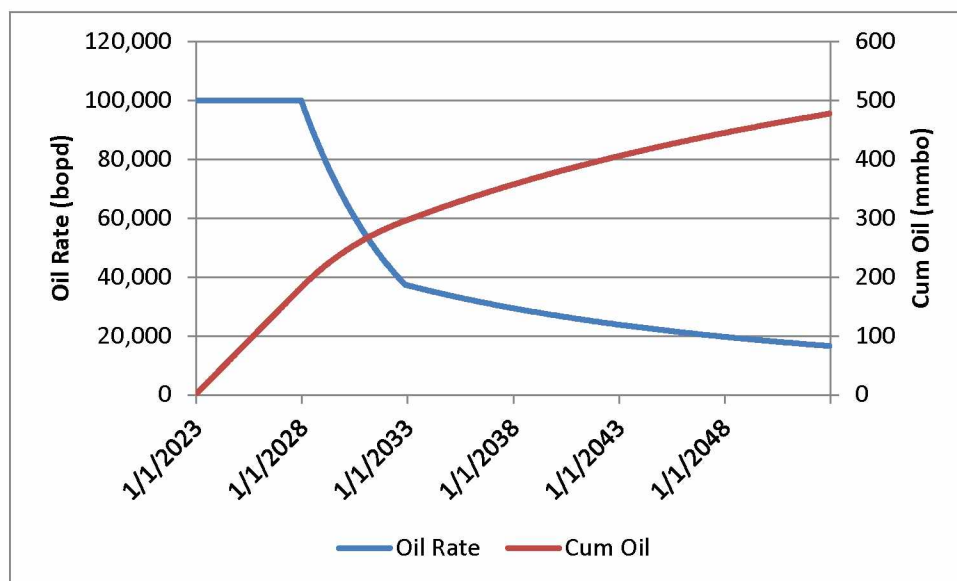


FIGURE 235: HYPOTHETICAL PIKKA DEVELOPMENT PRODUCTION PROFILE BASED ON PRESS RELEASES

### 17.3. HORSESHOE

Horseshoe is a continuation of Nanushuk play fairway in the Pikka Unit. The discovery was confirmed in 2016 with the Horseshoe 1 well. Bill Armstrong in an interview with the Petroleum News in 2016 said “We believe we have a proven oil pool that covers more than 25,000 acres, at a shallow depth of only 4,100 feet, with an oil column of 650-plus feet, up to 225 feet of net pay and an average porosity of 22 percent. Individual wells should be in excess of 10 million barrels each...Dream oil fields are still there to be found, especially in Alaska.” (Cashman, Armstrong Rumors Bunk, 2017). Although there have been many wells in Alaska that have produced more than 10 million barrels, no field has averaged more than 6 million barrels per well after full development. Horseshoe is estimated to be a 1.2 billion barrel discovery, which would make it the third largest field on the North Slope in terms of potential recovery. Since there is only a single well in Horseshoe, it is highly likely the recovery numbers will continue to change as more appraisal wells are drilled.

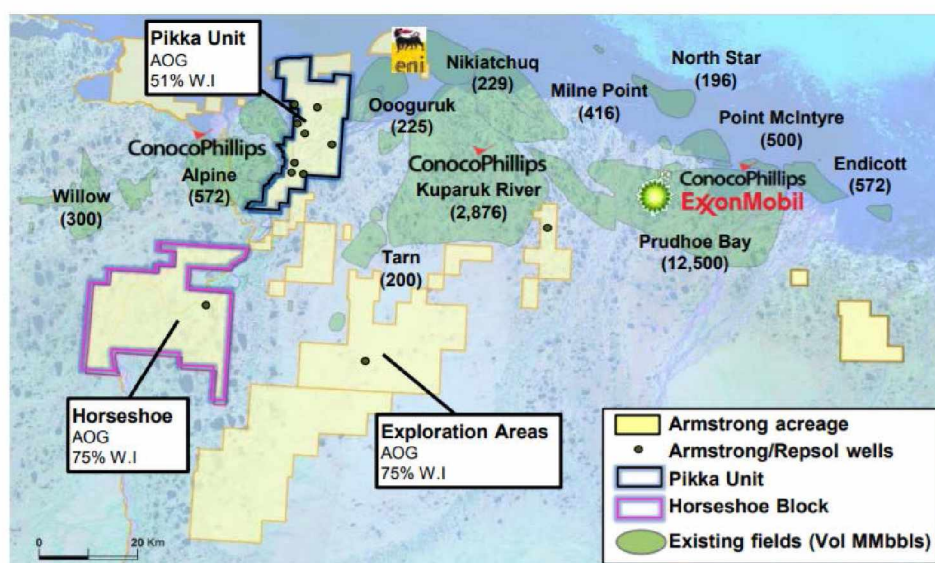


FIGURE 236: HORSESHOE LOCATION MAP (OIL SEARCH LIMITED, 2017)

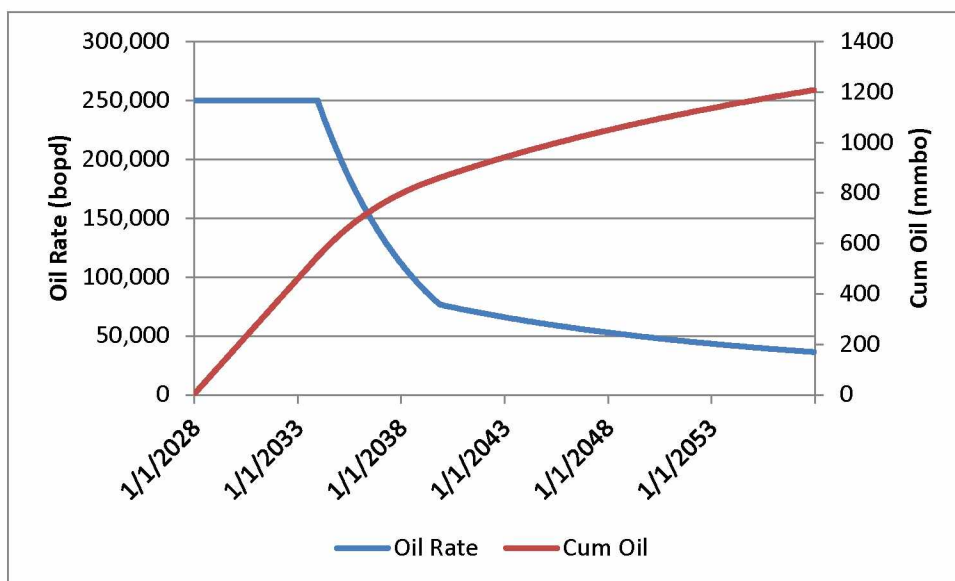


FIGURE 237: HYPOTHETICAL 1.2 BILLION BARREL HORSESHOE DEVELOPMENT PROFILE ASSUMING FIRST PRODUCTION 5 YEARS AFTER PIKKA

#### 17.4. SMITH BAY

The Smith Bay Field is a potentially massive offshore field northwest of Teshekpuk Lake in NPRA with an estimated 6 billion barrels of 40-45 degree API oil. Caelus is the operator and estimates 1.8-2.4 billion barrels of oil are recoverable, with peak rates of 200,000 bopd. Caelus drilled CT-1 and CT-2 in 2015 and found 183 net feet of pay in one well and 223 net feet in the other, and expects potential well rates of 8,000-10,000 bopd per well, or 8 to 9 million barrels of oil per well (Lidji E. , *The Explorers 2017: Caelus Sitting on a Smith Bay Elephant*, 2017). The formation is reported as being tight; however permeability measurements have not been made public. Using other North Slope production trends as analogs, and assuming Caelus predicted 8-9 mmbo for producers and planned a 1:1 Producer:Injector ratio; 200 net feet of pay with 0.5 cp viscosity oil, it would require 25-100 mD permeability to fall in trend for fields that averaged more than 4 million barrels per well as seen in Figure 16. To achieve 1.8 Billion barrels recovery with peak rates of 200,000 bopd, it would require 25 years of production at peak rate. A balanced development with a plateau rate 200,000 bopd would produce about 1 billion barrels. Kuparuk, a field of similar recovery volumes, had a plateau rate around 300,000 bopd that lasted about 10 years.



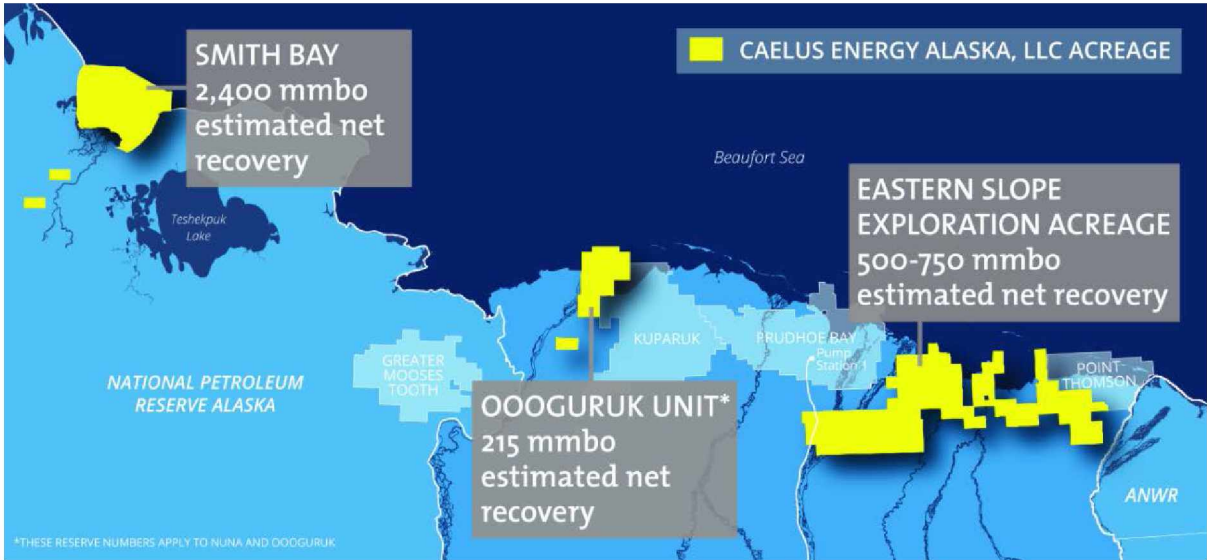


FIGURE 238: CAELUS LEASE HOLDINGS (CAELUS ENERGY LLC, N.D.)

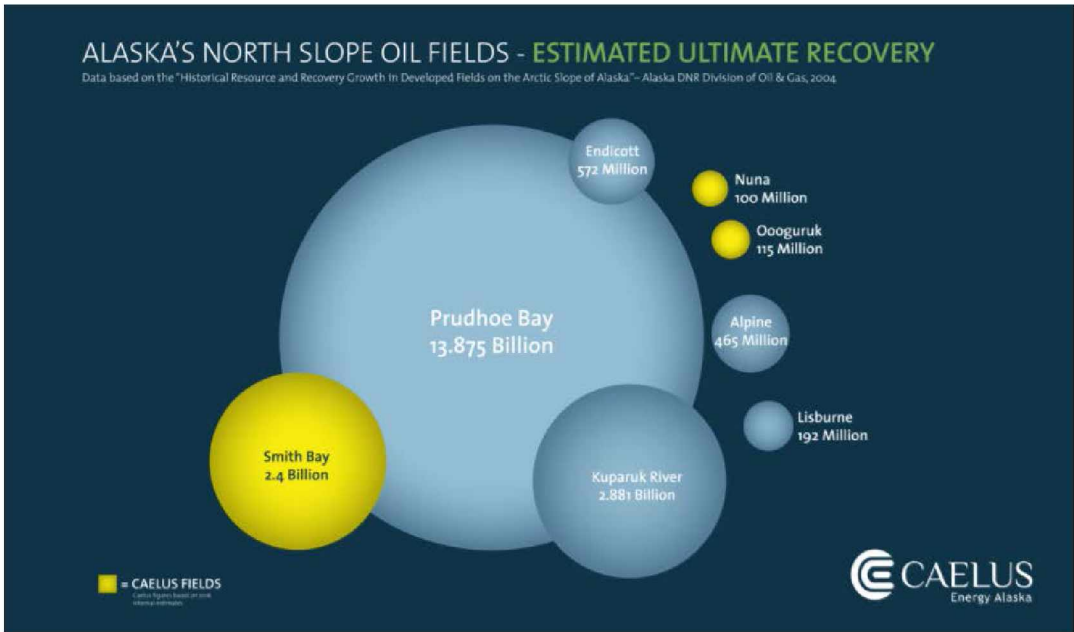


FIGURE 239: SMITH BAY ESTIMATED EUR COMPARED TO OTHER NORTH SLOPE FIELDS (CAELUS ENERGY LLC, N.D.)

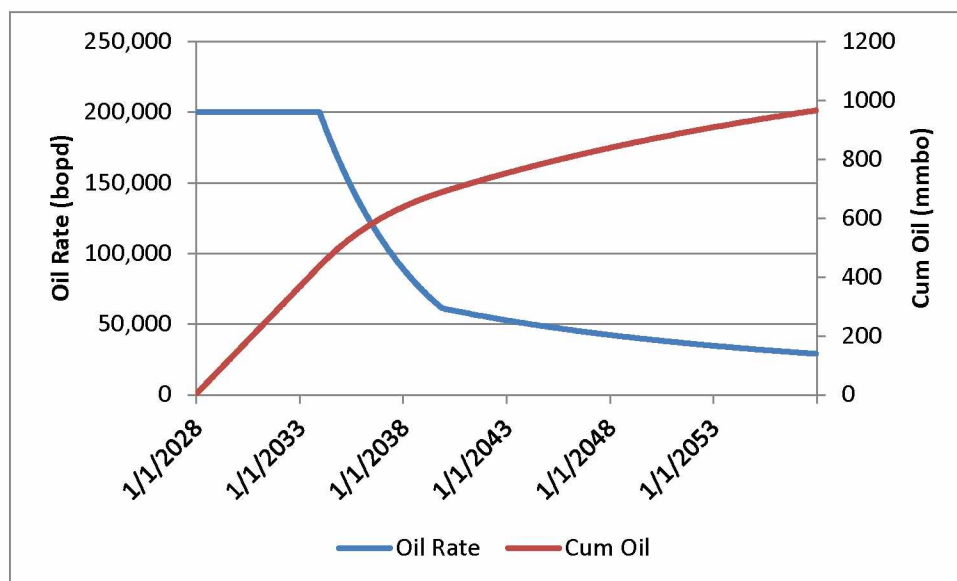


FIGURE 240: SMITH BAY HYPOTHETICAL DEVELOPMENT PROFILE WITH REDUCED RECOVERY

## 17.5. NUNA

The Nuna project is estimated to produce 75-150 million barrels of oil with a peak production of 15,000-18,000 barrels of oil per day (Caelus Energy LLC, n.d.). Caelus also applied for royalty modification for its Nuna project targeting the Torok formation and in 2015 it was reduced from 12.5-16.6667% to 5% (Department of Natural Resources, 2015). The royalty modification has since expired since the work agreement of spending at least \$260 million and beginning sustained production by September 2017 (Lidji E. , State Declines to Extend 2015 Royalty Relief Decision; Company Intends to Re-Appl, 2017). The Development is expected to cost \$1.4 billion dollars and requires a new onshore drilling pad and facility tie-ins (Caelus Energy LLC, n.d.). The Company has spent \$110 million to date on the project and plans to continue the project with a start-up in “2018 or later” and intends to reapply for royalty modification (Lidji E. , State Declines to Extend 2015 Royalty Relief Decision; Company Intends to Re-Appl, 2017).

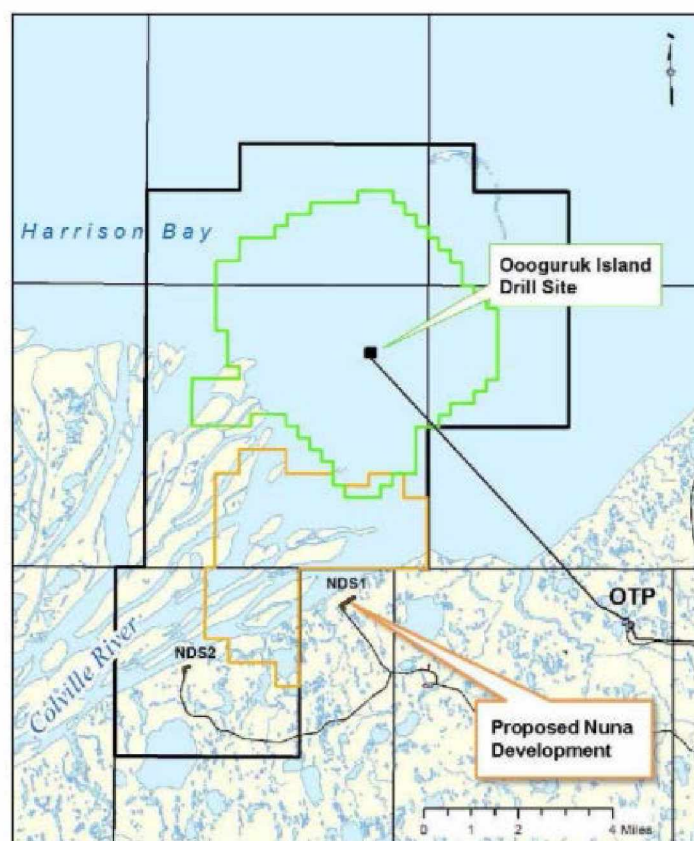


FIGURE 241: NUNA DEVELOPMENT MAP (LEGISLATIVE BUDGET AND AUDIT COMMITTEE)

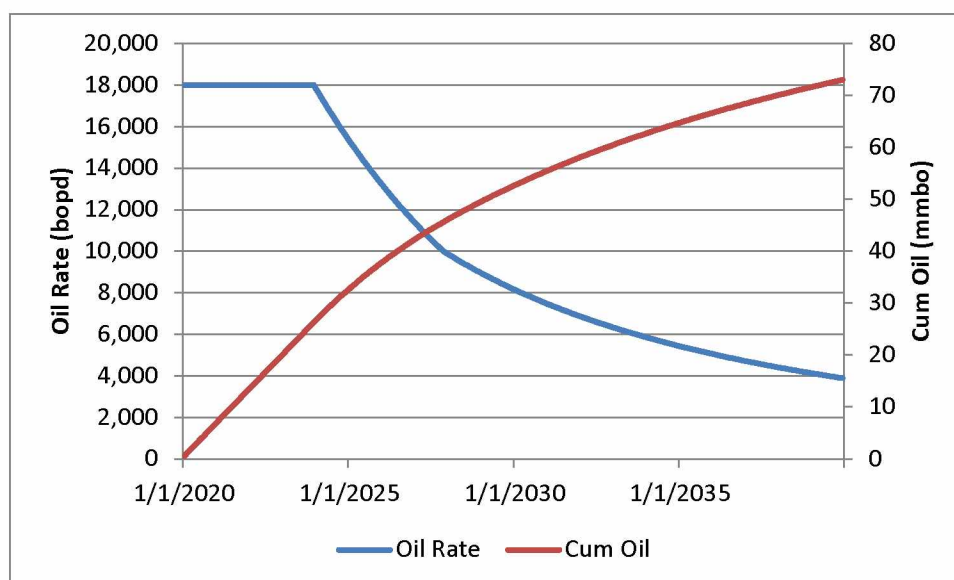


FIGURE 242: HYPOTHETICAL NUNA DEVELOPMENT PROFILE

## 17.6. HARRISON BAY

The Harrison Bay targets, also known as Nikaitchuq North, are operated by Nikaitchuq who has a 40% working interest. The other interest owners are Shell (40%) and Repsol (20%), though the drilling occurs from Spy Island where ENI is a 100% owner and has 32 existing wells (ENI US Operating Co. Inc., 2017). These exploration wells are expected to have a measured depth of 34,000 feet and a true vertical depth of 8,000 feet, and would produce to existing facilities at Nikaitchuq.

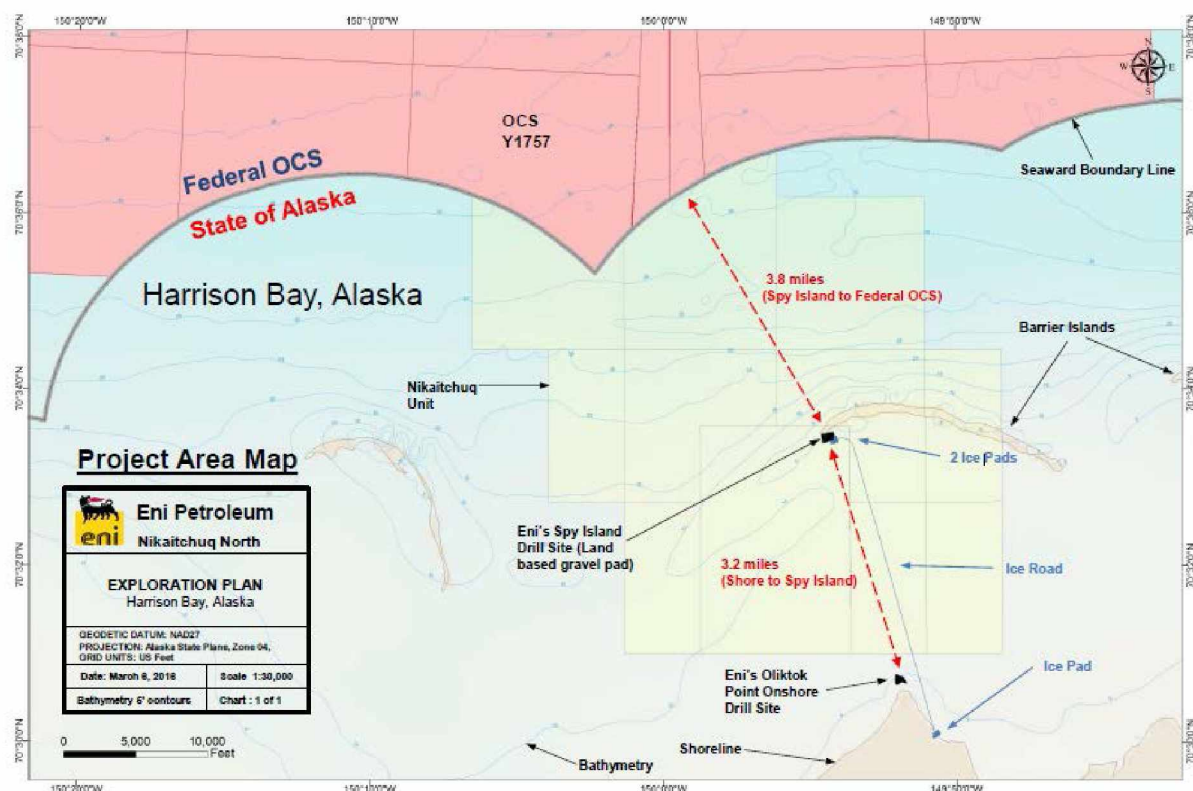


FIGURE 243: HARRISON BAY PROJECT AREA MAP (ENI US OPERATING CO. INC., 2017)

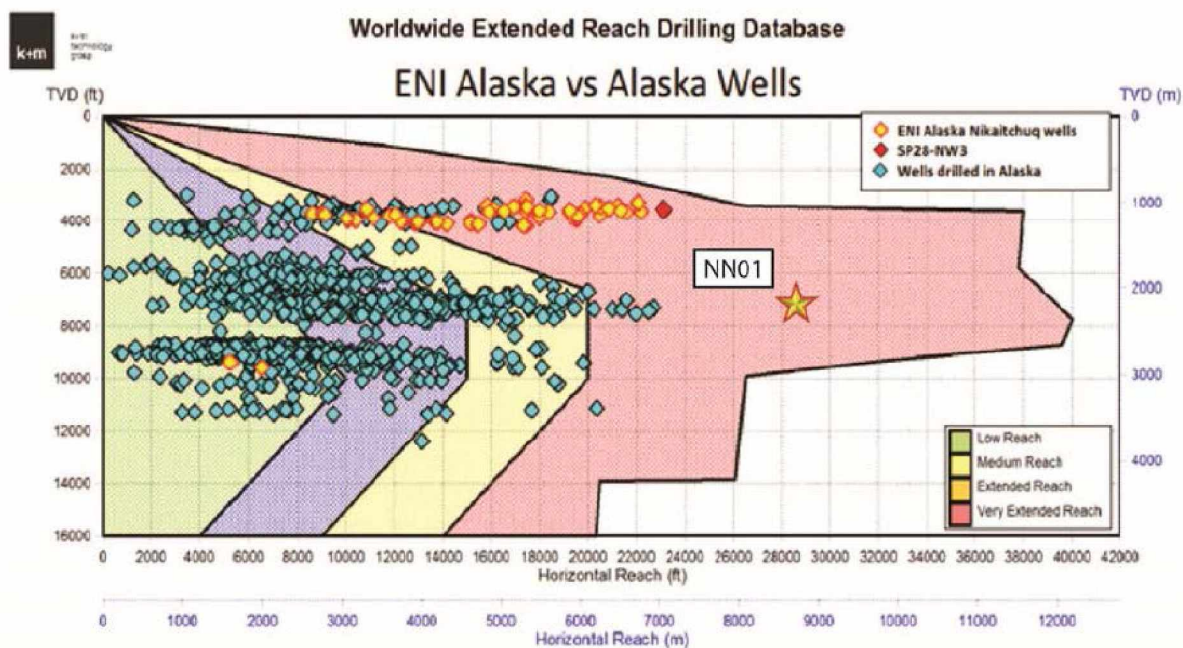


FIGURE 244: HARRISON BAY EXTENDED REACH COMPARED TO OTHER ALASKAN WELLS (ENI US OPERATING CO. INC., 2017)



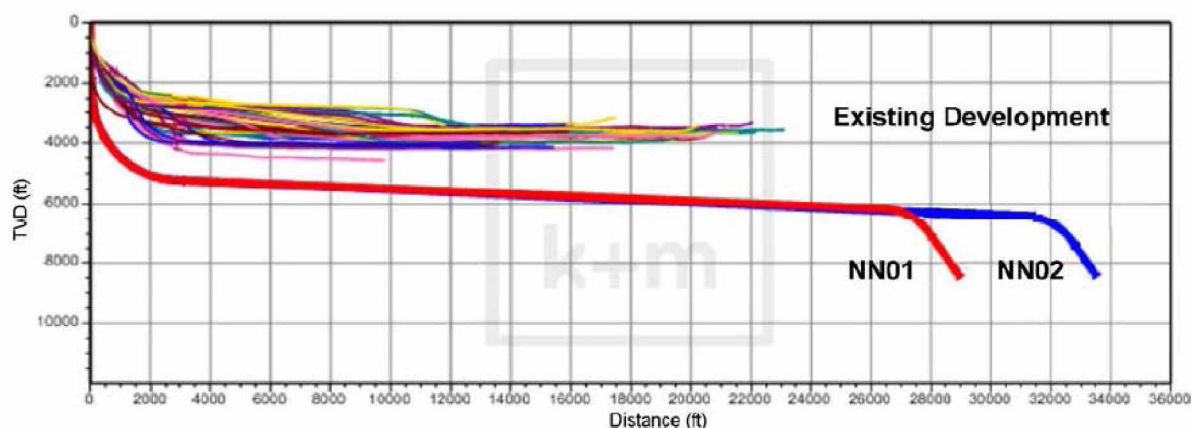


FIGURE 245: NIKAITCHUQ NORTH AND EXISTING DEVELOPMENT TRAJECTORIES (ENI US OPERATING CO. INC., 2017)

TABLE 11: HARRISON BAY EXPLORATION ACTIVITIES (ENI US OPERATING CO. INC., 2017)

Proposed Activity	Start Date	End Date	No. of Days
Drill Nikaichuq North (NN01)	12/10/2017	02/13/2018	65
NN01 Flow Test	02/13/2018	03/10/2018	25
NN01 P&A	03/10/2018	03/25/2018	15
Drill NN01 Sidetrack to Lateral & Complete	03/25/2018	04/14/2018	20
Perform Flow Test – Suspend	04/14/2018	05/14/2018	30
Drill Nikaichuq North (NN02)	12/01/2018	02/14/2019	75
NN02 Flow Test	02/14/2019	03/11/2019	25
NN02 P&A	03/11/2019	03/26/2019	15
Drill NN02 Sidetrack to Lateral & Complete	03/26/2019	04/21/2019	26
Perform Flow Test – Suspend	04/21/2019	05/23/2019	32

Note: No drilling operations are planned during summer.

## 17.7. GMT1

The Greater Mooses Tooth 1 (GMT1, formally known as “Lookout”) is an Alpine satellite in NPRA to the west of CD5, and will use existing Alpine Facilities (ConocoPhillips Alaska). The development is expected to cost \$900 million and production is expected to peak at 30,000 bopd. First oil is expected to occur at the end of 2018. The initial planned development includes four producers and five injectors, with the potential to increase to 33 wells (Brehmer, 2016).

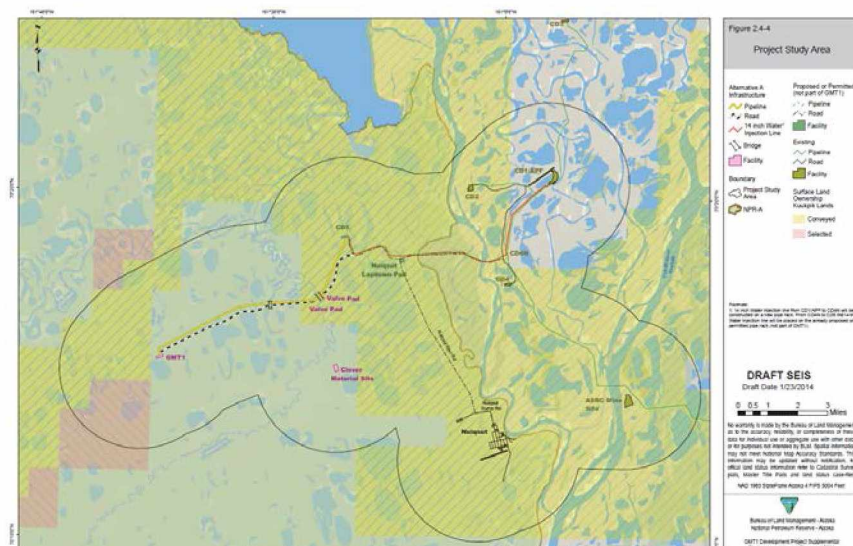


FIGURE 246: GMT1 LOCATION MAP (BUREAU OF LAND MANAGEMENT, 2014)

TABLE 12: PROECTED CRUDE PRODUCTION FROM GMT1 AS PREDICTED BY THE ALASKA DEPARTMENT OF REVENUE (BUREAU OF LAND MANAGEMENT, 2014)

Year	Alpine	Total Alaska North Slope Barrels Per Day	GMT1*
2013	66,700	538,300	
2014	64,300	526,600	
2015	60,300	512,800	
2016	60,500	499,700	
2017	55,500	478,900	2,000
2018	47,200	443,300	20,000
2019	40,100	422,400	18,075
2020	34,400	399,400	16,250
2021	29,800	372,300	14,375
2022	26,000	344,500	12,500
2023			10,596
2024			8,750
2025			6,875
2026			5,000
2027			4,096
2028			4,435
2029			4,178
2030			3,933
2031			3,694
2032			3,488
2033			3,285
2034			3,094
2035			2,906
2036			2,744
2037			2,584
2038			2,434
2039			2,286
2040			2,159
2041			2,033
2042			1,914
2043			1,798
2044			1,688
2045			1,599
2046			1,506
2047			1,414
2048			1,336
2049			1,258
2050			1,185



TABLE 13: COMPARISON OF ALTERNATIVE CAPITAL EXPENDITURES, ROYALTIES, AND TAXES (IN 2014 \$ MILLIONS) (BUREAU OF LAND MANAGEMENT, 2014)

Alternative	Description	Total CAPEX	Royalties	Property Tax	SCIT	Severance Tax	Royalties + Tax
Alternative A	CPAI Proposed GMT1 Project	\$1,540	\$1,041	\$275	\$279	\$455	\$2,050
Alternative B	Avoid Fish Creek Setback	\$1,596	\$1,041	\$288	\$275	\$431	\$2,034
Alternative C	Alternative Access (via Nuiqsut)	\$1,739	\$1,041	\$316	\$264	\$362	\$1,982
Alternative D1	Roadless Access to GMT-1	\$1,955	\$1,041	\$345	\$194	\$127	\$1,707
Alternative D2	Roadless Access with Seasonal Drilling Restriction	\$2,353	\$921	\$399	\$120	-\$92	\$1,348

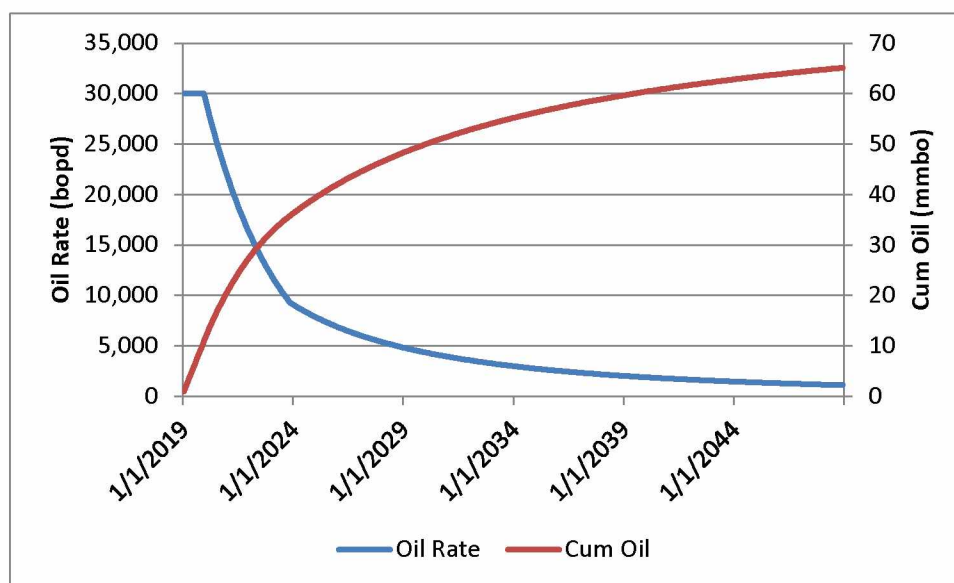


FIGURE 247: GMT1 HYPOTHETICAL DEVELOPMENT PROFILE

## 17.8. GMT2

The GMT2 development, previously known as “Spark” is southwest of GMT1 and expected to cost \$1 billion and production is expected to peak between 25,000- 30,000 bopd. First oil is currently planned for the end of 2020.

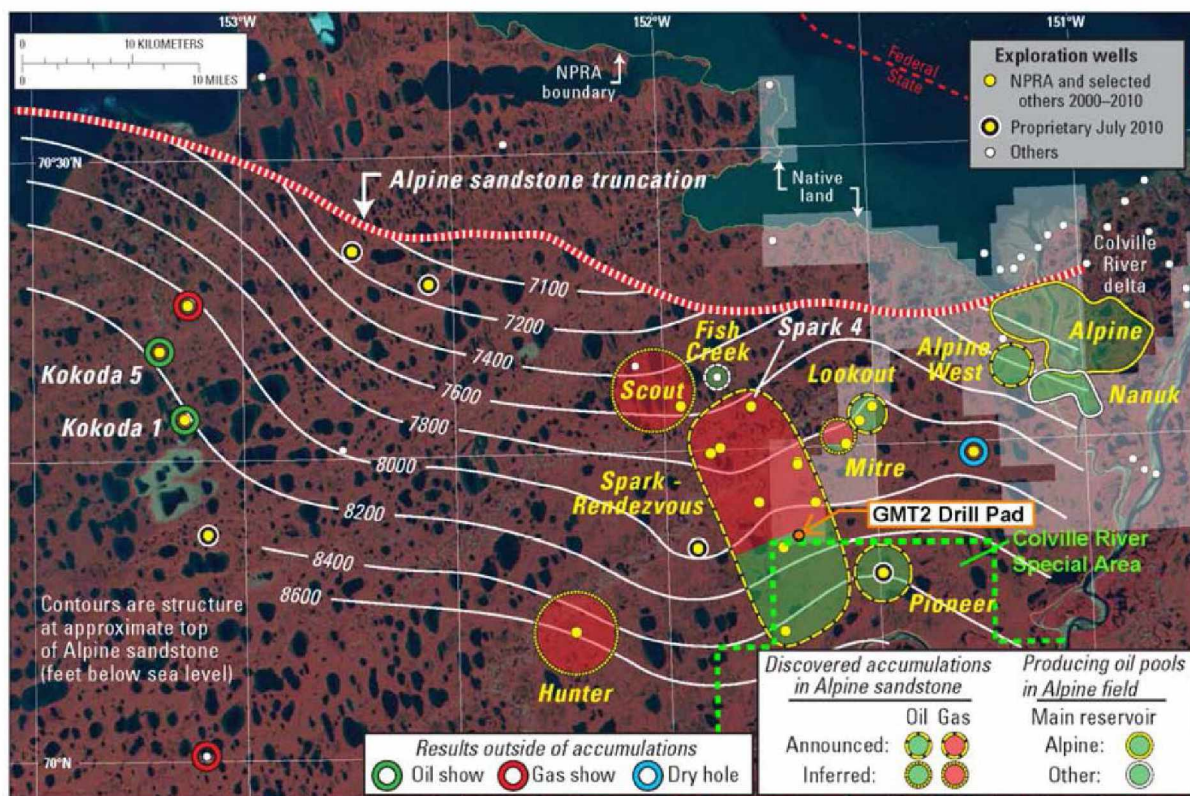


FIGURE 248: OIL AND GAS ACCUMULATIONS IN OR NEAR NORTHEAST NPRA FROM HOUSEKNECHT ET AL (BUREAU OF LAND MANAGEMENT, 2016)

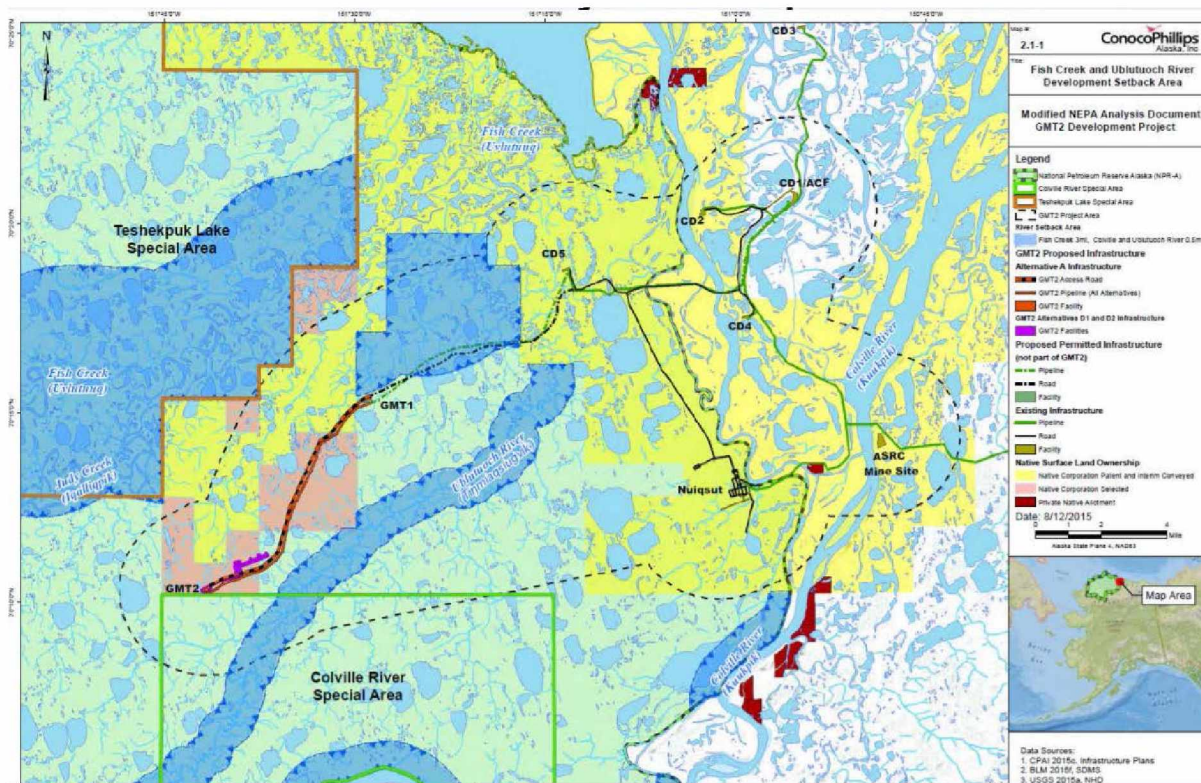


FIGURE 249: GMT2 PROJECT MAP (BUREAU OF LAND MANAGEMENT, 2016)



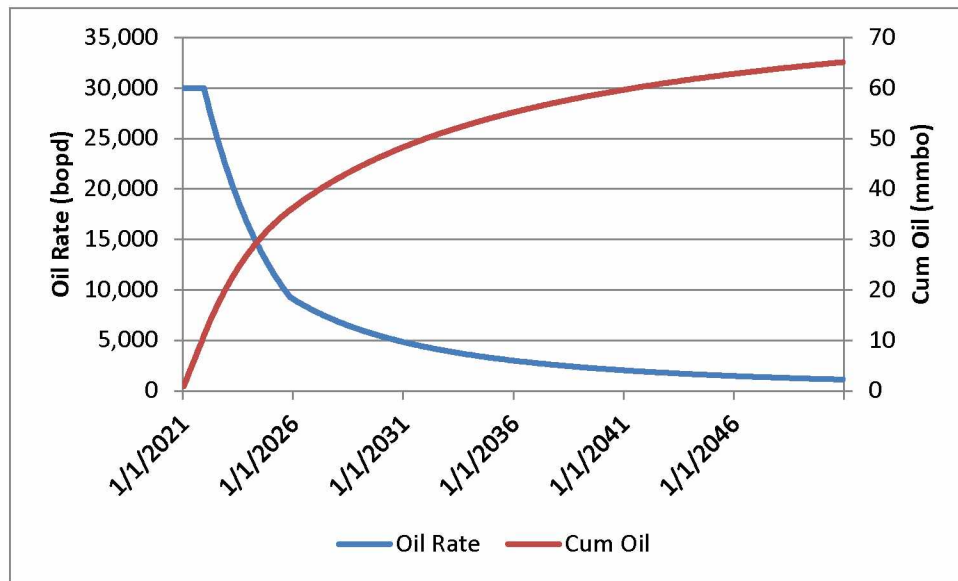


FIGURE 250: GMT2 HYPOTHETICAL DEVELOPMENT PROFILE

## 17.9. WILLOW

The Willow Discovery is in the Greater Mooses tooth Unit and is estimated that it can produce up to 100,000 bopd and hold 300 million barrels of recoverable oil. Initial production may occur as early as 2023 (ConocoPhillips Alaska, 2017). It is in the Nanushuk formation, and is a similar Brookian clinoform topset play as Pikka.

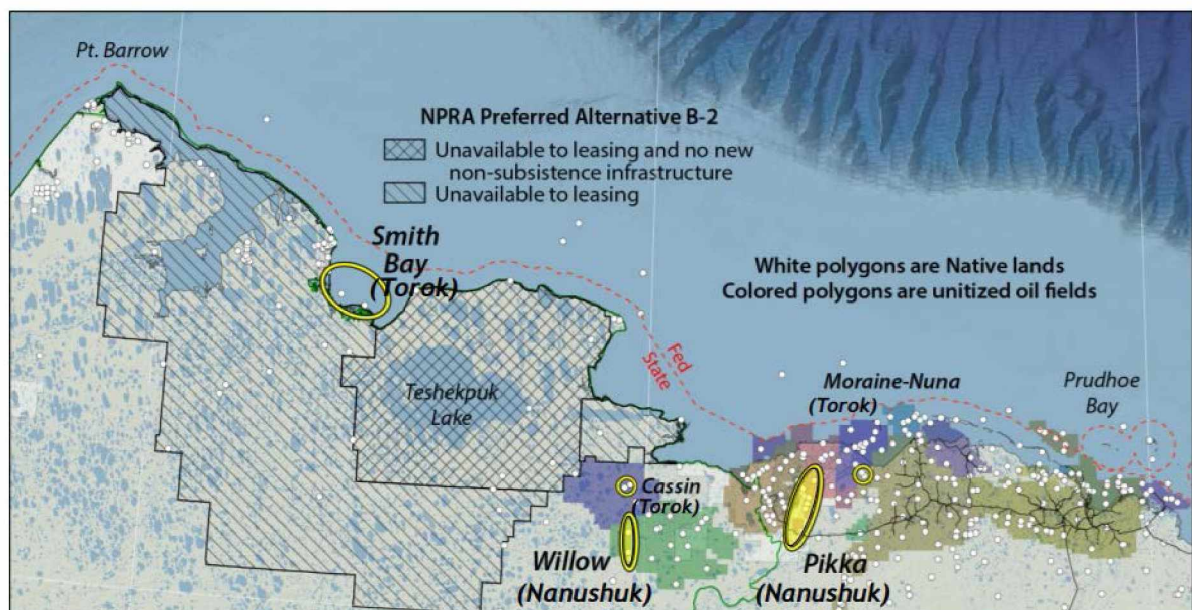


FIGURE 251: RECENT NANUSHUK AND TOROK DISCOVERIES (ALASKA DEPARTMENT OF NATURAL RESOURCES, DOG, 2017)

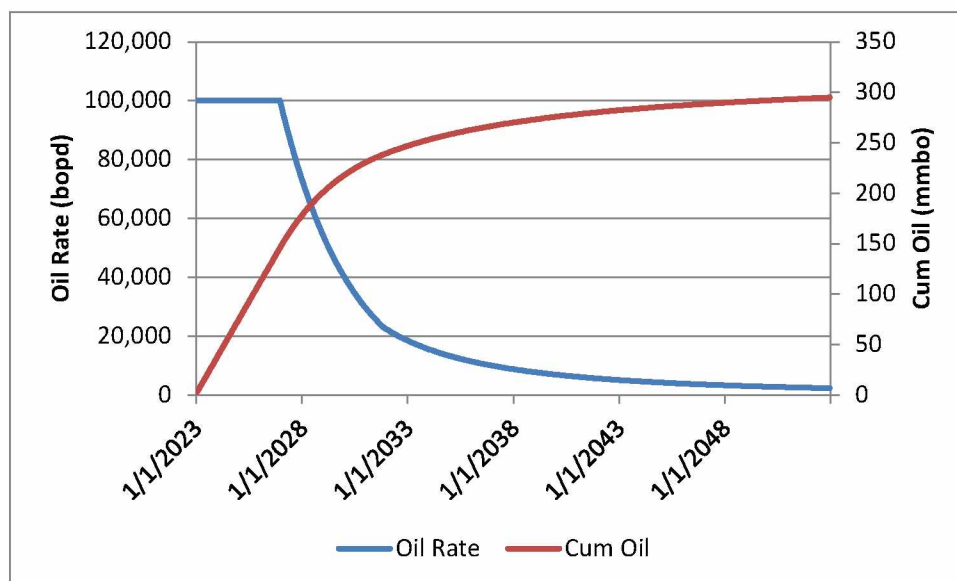


FIGURE 252: HYPOTHETICAL WILLOW DEVELOPMENT PROFILE

### 17.10. LIBERTY

The Liberty field sits in 19 feet of sheltered waters in Foggy Island bay, to the east of Endicott and is owned by BP and Hilcorp, who is the operator. Although there have been multiple development plans in the past, such as ultra-extended-reach drilling at the expanded SDI drillsite of the Endicott field, current development plan is an island development similar to Northstar. Four wells have already penetrated the reservoir as seen in Figure 254. The Liberty field is expected to be similar to the neighboring Endicott field, and produce out of the Kekiktuk formation. There is an estimated 230 million barrels of oil in place, if analog field recovery factor (Endicott - 55%) can be achieved; Liberty may produce up to 167 MMBO (Hilcorp Alaska, LLC, 2015).



FIGURE 253: LIBERTY FIELD LOCATION (HILCORP ALASKA, LLC, 2015)

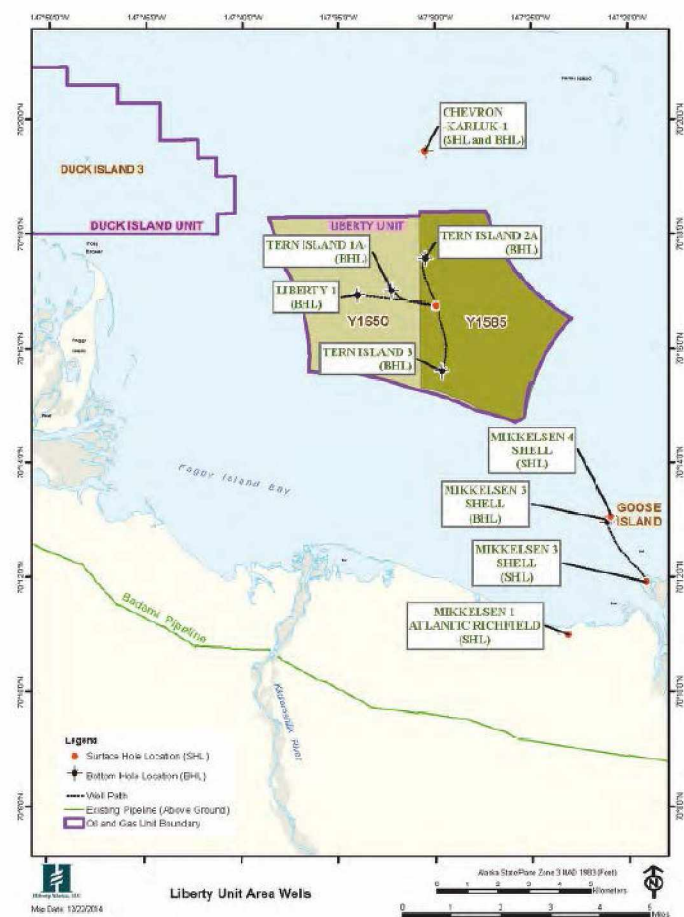


FIGURE 254: LIBERT UNIT MAP WITH AREA WELLS (HILCORP ALASKA, LLC, 2015)

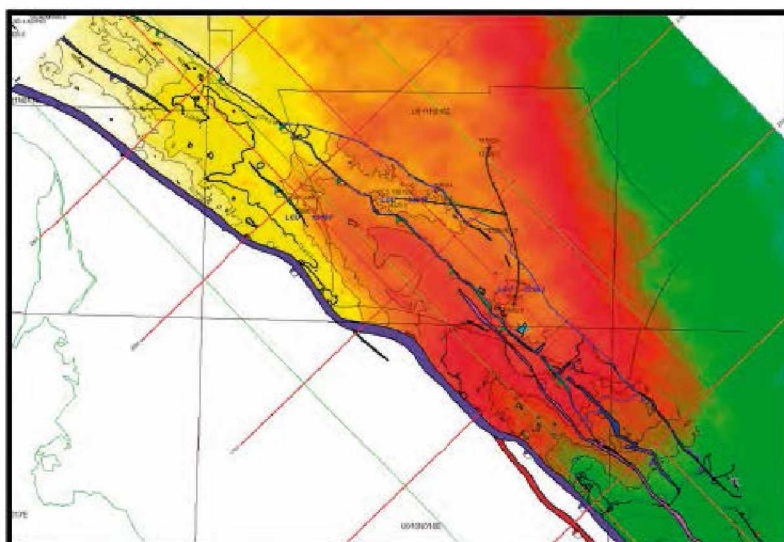


FIGURE 255: LIBERTY STRUCTURE MAP - TOP RESERVOIR (HILCORP ALASKA, LLC, 2015)



TABLE 14: LIBERTY RESERVOIR ROCK PROPERTIES (HILCORP ALASKA, LLC, 2015)

PROPERTY	LIBERTY	ENDICOTT (ANALOG FIELD)
Average Gross Pay Thickness	230 ft	800 ft
Average Net Pay Thickness	190 ft	400 ft
Average Porosity, Range	18 – 20%	18 – 20%
Average So, Range	90 – 95%	90 – 95%
Average Permeability, Range	500 – 1,500 mD	400 – 1,600 mD

TABLE 15: LIBERTY RESERVOIR FLUID PROPERTIES (HILCORP ALASKA, LLC, 2015)

PROPERTY	LIBERTY	ENDICOTT (ANALOG FIELD)
API gravity	24° to 27° API	23° to 24 °API
Viscosity	0.68 cP	0.9 cP
Reservoir Temperature	215 °F	218 °F
Solution GOR, Rs	872 SCF/STB	770 SCF/STB
B <sub>o</sub>	1.47 RB/STB	1.35 RB/STB
Psat (Bubble Point)	4973 psia	4838 psia

#### 17.10.1. DEVELOPMENT

The Liberty development is expected to consist of five producers and four injectors with peak rates of 10,000-15,000 bopd. Peak field rate is anticipated to reach 60,000-70,000 bopd, and have an economic field life of 15-20 years yielding an estimated 60-100 million barrels (Hilcorp Alaska, LLC, 2015). This is a 26%-43% recovery factor, about 7-11 MMBO/well or 12-20 MMBO/producer. This development has a low well density to support the high recovery per well (and minimizes risk and cost of additional wells), however it also lowers the field recovery factor compared to the analog. The Liberty project is also unique in that it intends to use truckable modules for its production facilities rather than utilizing a seal lift like most other facilities on the North Slope (Hilcorp Alaska, LLC, 2015).

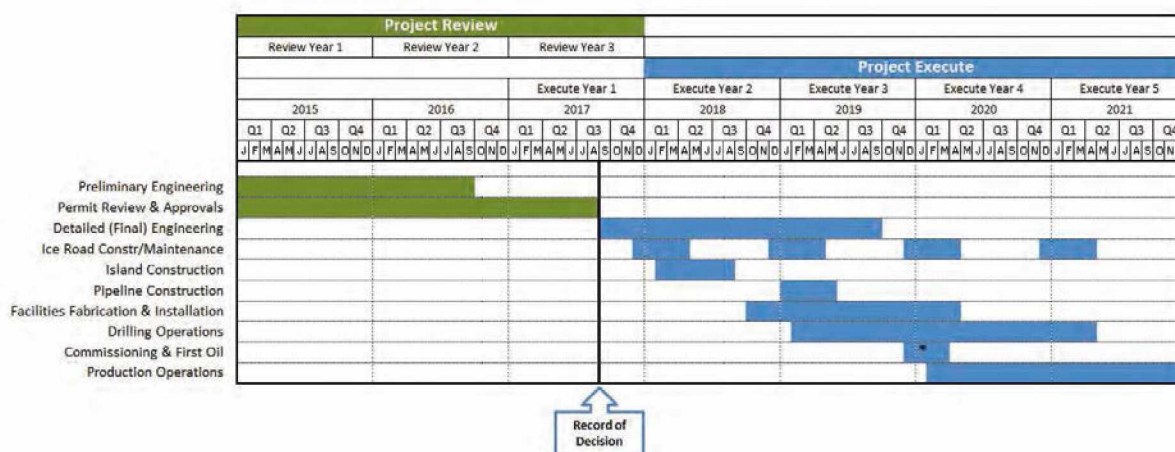


FIGURE 256: LIBERTY PROJECT SCHEDULE (HILCORP ALASKA, LLC, 2015)



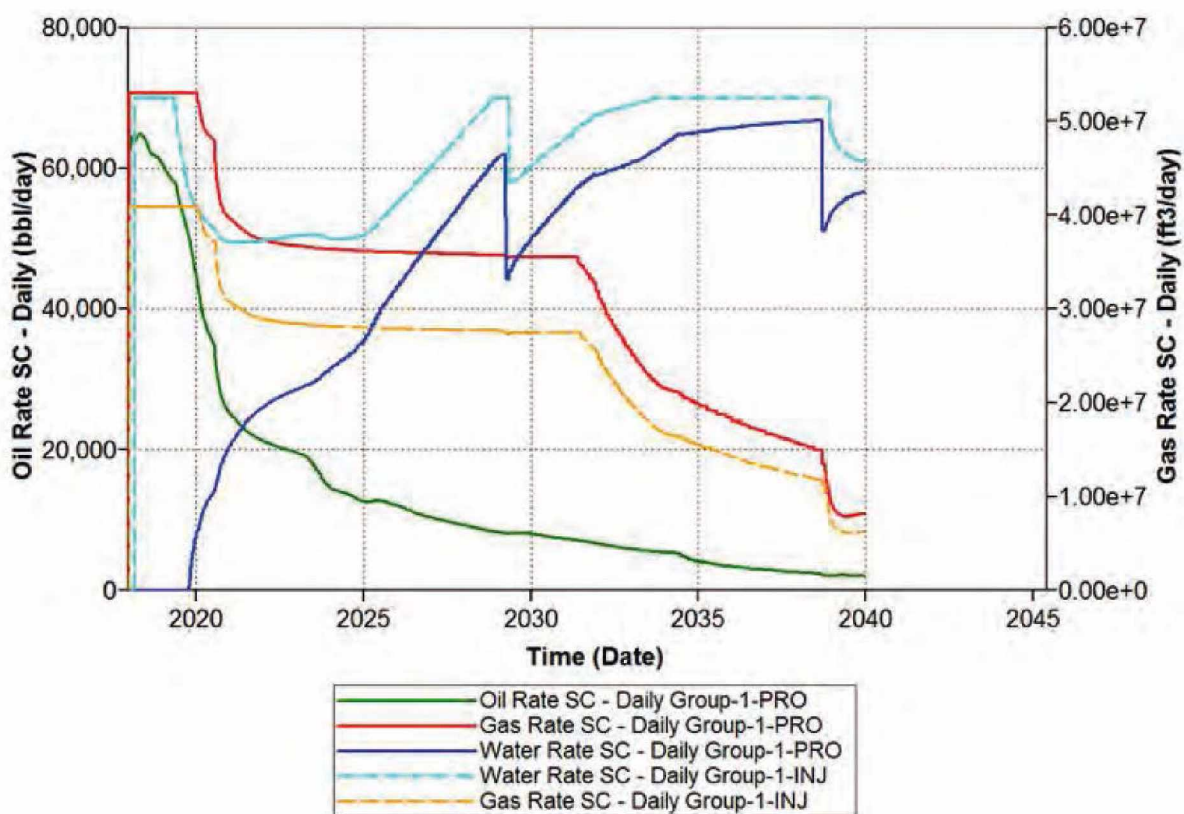


FIGURE 257: LIBERTY PROPOSED DEVELOPMENT PROFILE (HILCORP ALASKA, LLC, 2015)

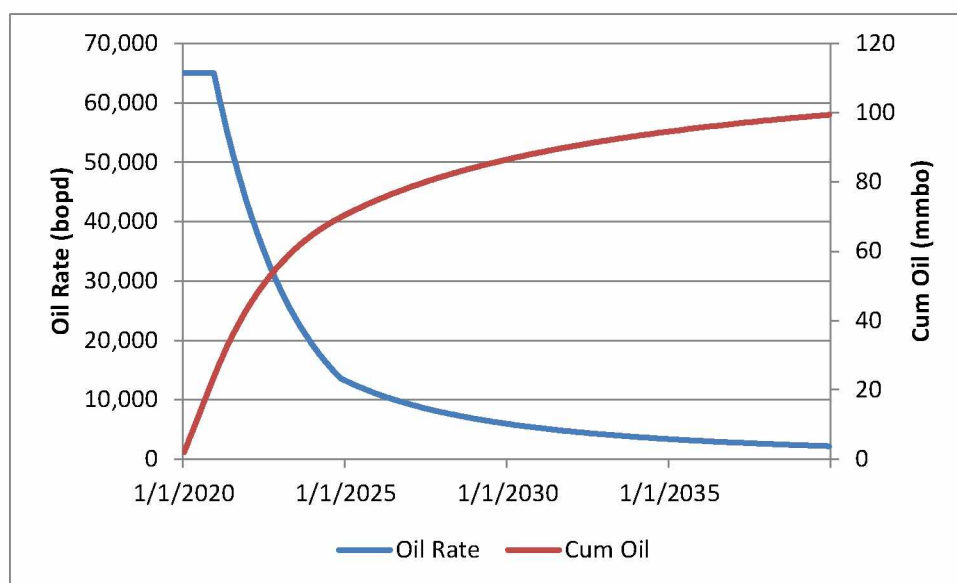


FIGURE 258: HYPOTHETICAL LIBERTY FORECAST BASED ON PROPOSED PROFILE

### 17.11. UMIAT

The Umiat field was discovered by the Navy in 1946 and has an estimated oil in place of 1.5 billion barrels in place (Hanks, et al., 2014). Current ownership of the leases is held by Malamute Energy, however the company has no plans of starting development drilling in the next year (Bailey, Malamute Files Contingency Plan For Umiat; No Immediate Drilling, 2017). Linc Energy, a recent owner of the Umiat Field, estimated field reserves around 155 million barrels of 45 degree API oil (Bradner, 2015). Linc's development plan for the field included

35 wells, producing 30,000 bopd after scaling back from development programs ranging between 70-150 wells and 45,000 bopd (Lidji E. , Linc Bankruptcy Filing, 2016). Although it has been a known accumulation for 70 years, it has yet to come on production, in part due to its remoteness.

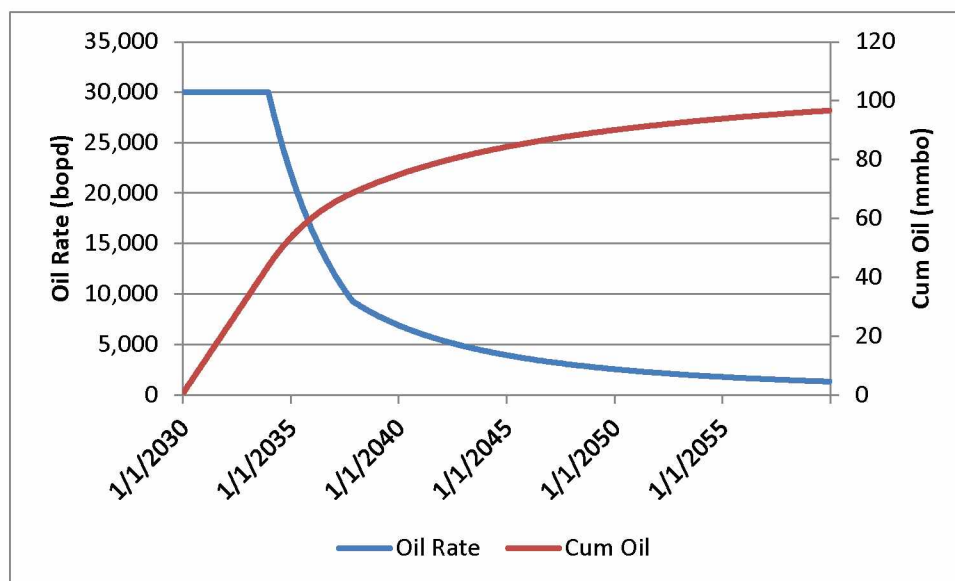


FIGURE 259: HYPOTHETICAL UMIAT FORECAST ASSUMING DEVELOPMENT IN 2030

## 18. TRANS ALASKA PIPELINE LOW FLOW

One of the ongoing concerns for the future of the North Slope is keeping the oil production high enough to maintain velocity in the pipeline to prevent major flow assurance problems. The minimum throughput of 800 mile long Trans Alaska Pipeline (TAPS) and what modifications will need to be made for ever decreasing oil production will be a major topic over the next few decades. Due to the fact that all North Slope fields share a single export line, when it becomes uneconomic or not feasible to run the line, all fields on the slope will be shut in, even if individually they may still be productive fields. Increased oil production on the North Slope helps prolong the life of all fields, as no recent discovery can maintain TAPS minimum flow individually.

### 18.1. TAPS LOW FLOW STUDY

In 2011, Alyeska, the operator of the TAPS, prepared a “Low Flow Impact Study.” This report detailed issues that arise as oil rates decrease, including water dropout and corrosion, ice formation, wax deposition, and geotechnical concerns around the buried portions of the pipeline. The conclusions of the study found that reliable operating could be achieved to 550,000 bopd under normal conditions, and could be extended to about 350,000 with mitigations in place such as adding additional heat (Alyeska Pipeline Service Company, 2011).



FIGURE 260: TRANS ALASKA PIPELINE SYSTEM (ALYESKA PIPELINE SERVICE COMPANY, 2011)

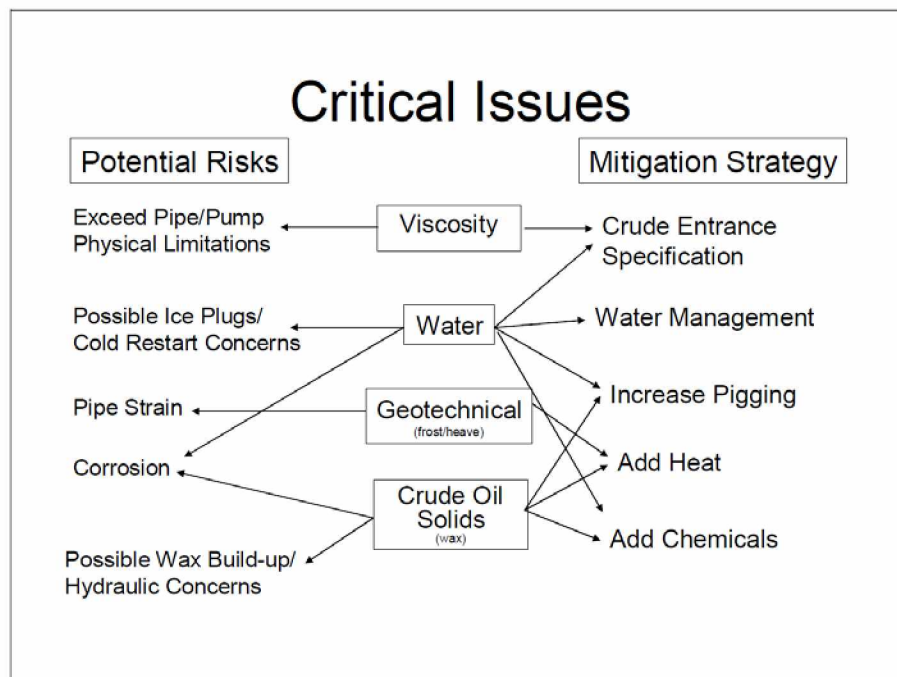


FIGURE 261: TAPS CRITICAL ISSUES AND SOLUTIONS AT LOW FLOW (ALYESKA PIPELINE SERVICE COMPANY, 2011)

TABLE 16: TRANS ALASKA PIPELINE OPERATING ASSUMPTIONS WITHOUT EXTERNAL HEAT (ALYESKA PIPELINE SERVICE COMPANY, 2011)

PS01 – NPM Flow Rate	PS1 – NPM Velocity	NPM to VPR Flow Rate	NPM to * VPR Velocity	VPR to ** VMT Flow Rate	VPR to VMT Velocity	Crude Oil Transit Time PS01 to VMT	Reynolds Number Min/Max
600,000 BPD	3.25 feet/sec	565,000 BPD	2.94 feet/sec	553,000 BPD	2.94 feet/sec	15.5 Days	5.48E+4 3.37E+5
500,000 BPD	2.7 feet/sec	465,000 BPD	2.4 feet/sec	453,000 BPD	2.4 feet/sec	18.7 Days	3.85E+4 2.81E+5
400,000 BPD	2.15 feet/sec	365,000 BPD	1.86 feet/sec	353,000 BPD	1.86 feet/sec	23.5 Days	2.53E+4 2.26E+5
300,000 BPD	1.61 feet/sec	265,000 BPD	1.33 feet/sec	253,000 BPD	1.33 feet/sec	31.8 Days	1.45E+4 1.71E+5

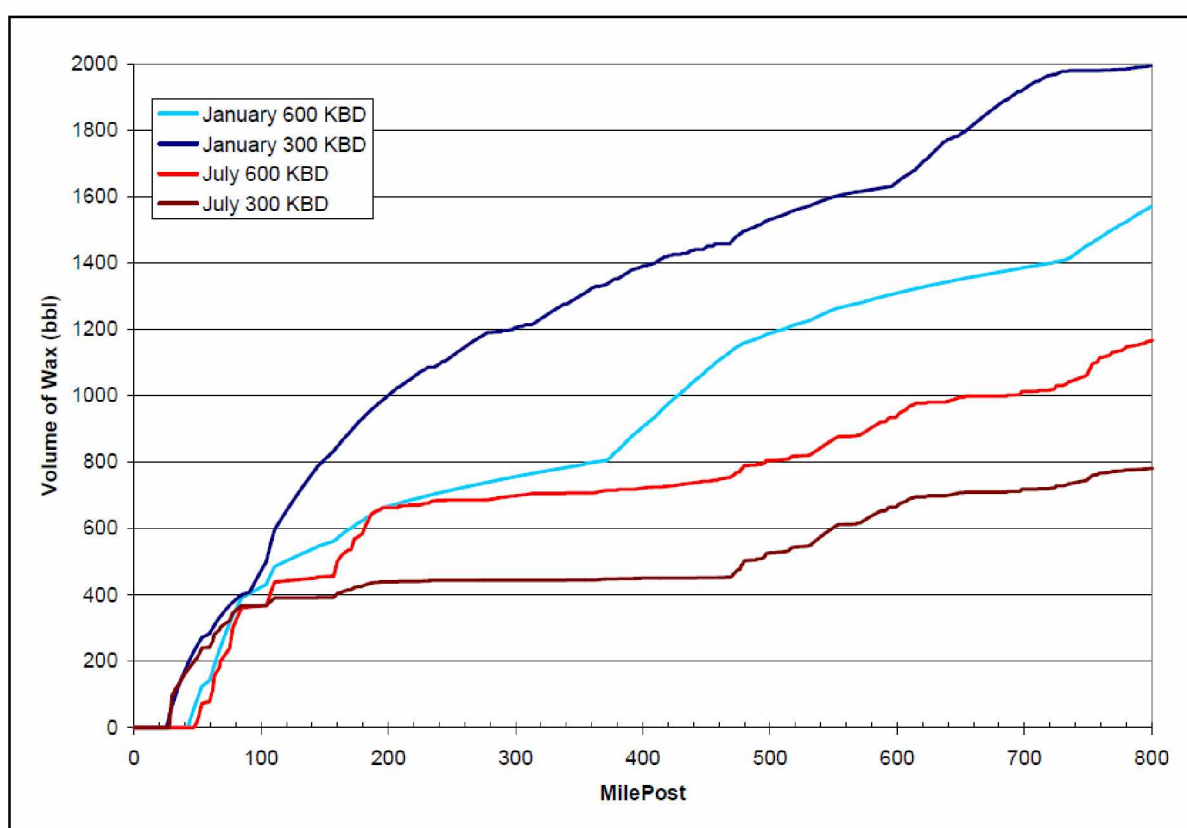


FIGURE 262: TAPS CUMULATIVE VOLUME OF WAX UNDER DIFFERENT FLOW RATES (ALYESKA PIPELINE SERVICE COMPANY, 2011)



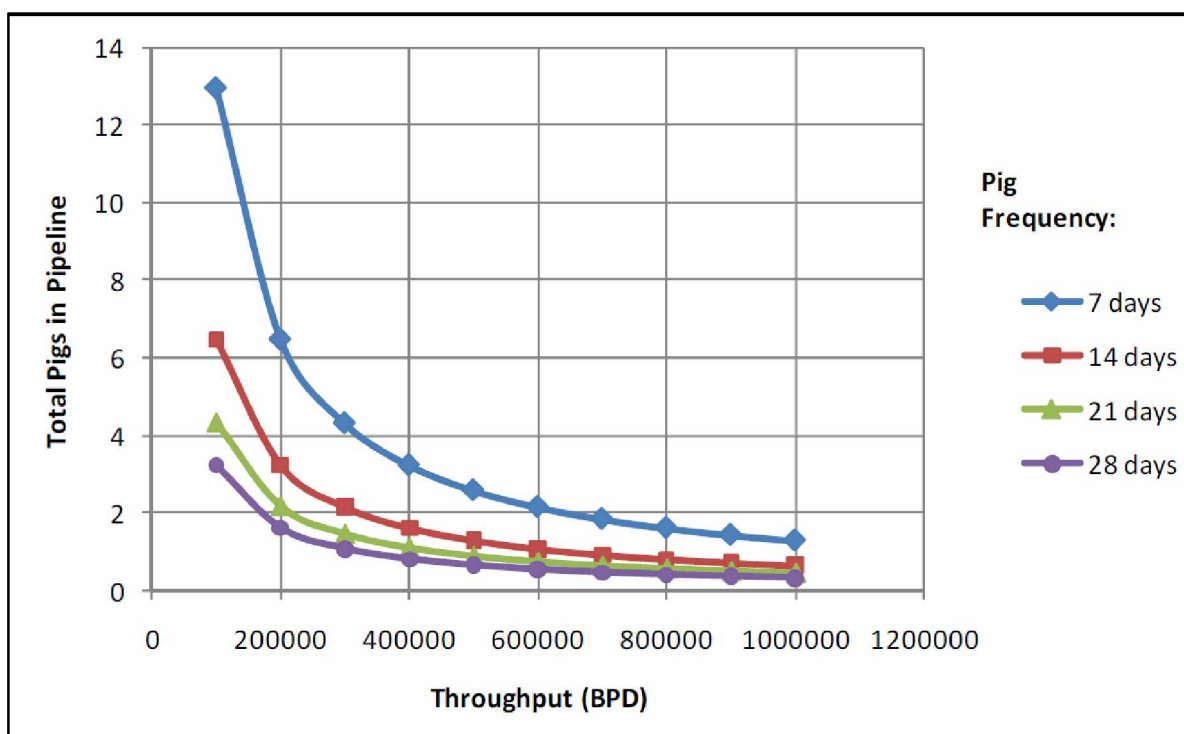


FIGURE 263: SCRAPER PIGS IN PIPELINE UNDER LOW FLOW (ALYESKA PIPELINE SERVICE COMPANY, 2011)

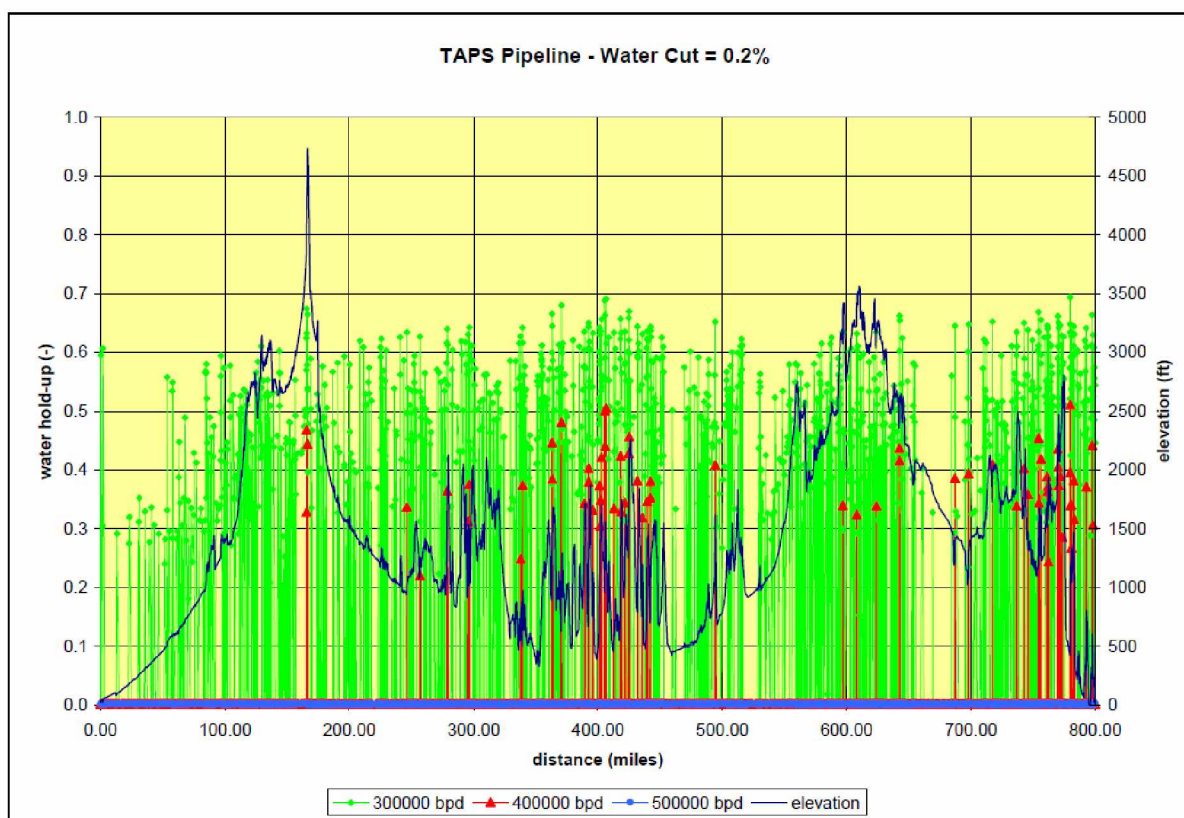


FIGURE 264: TAPS WATER HOLD-UP UNDER LOW FLOW (ALYESKA PIPELINE SERVICE COMPANY, 2011)

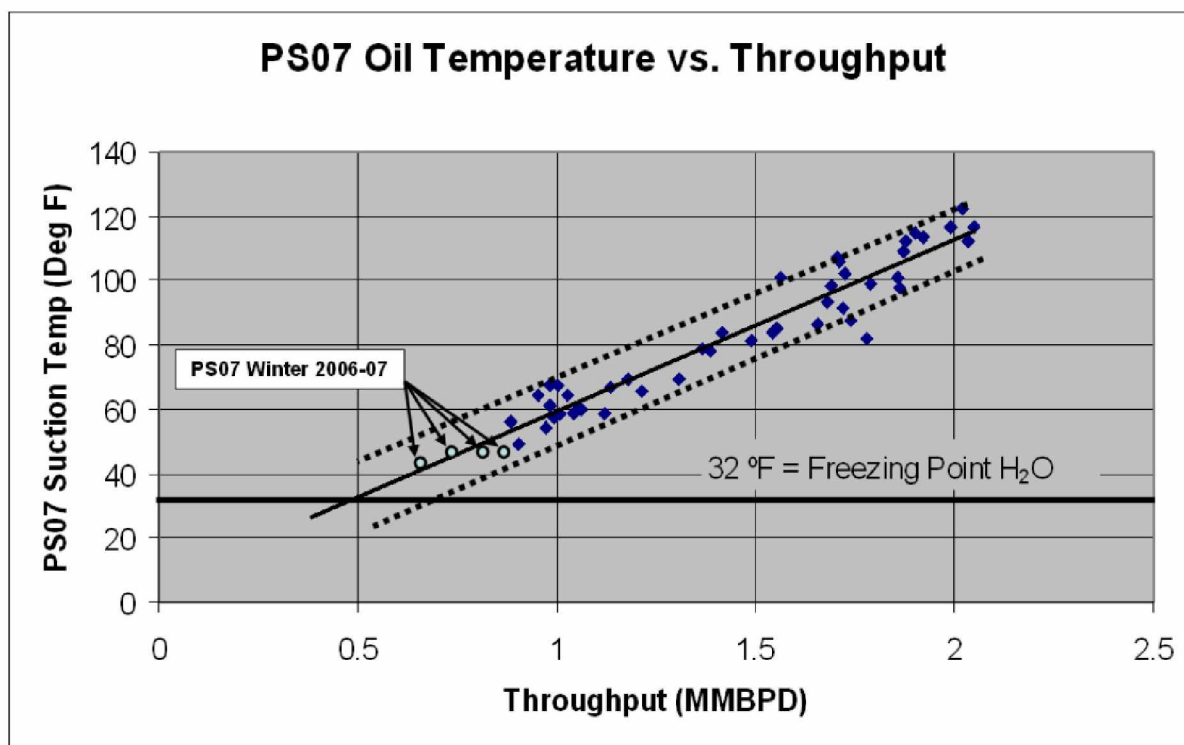


FIGURE 265: IMPACT OF TAPS THROUGHPUT ON CRUDE OIL TEMPERATURE (BP PIPELINES ALASKA, INC, 2010)

## 18.2. STATE OF ALASKA DECISION ON LOW FLOW

In December 2011 Judge Sharon Gleason in a court decision about the TAPS valuation for municipal property taxes assumed the low flow limit to be 100,000 bopd (Bailey, A TAPS Bottom Line, 2012). This was based on a BP document by Phil Carpenter who concluded throughput could be reduced to 70,000-100,000 bopd if heaters were installed along the line, at a cost of about \$3 billion (Bailey, A TAPS Bottom Line, 2012). As seen in Figure 272, without additional development, North Slope will fall below the Alyeska low flow study limit in the next ten years, and will reach 100,000 bopd in the next 40 years. Current planned developments, if successful, keep the North Slope above 350,000 bopd for an additional 10-15 years, as seen in Figure 275.



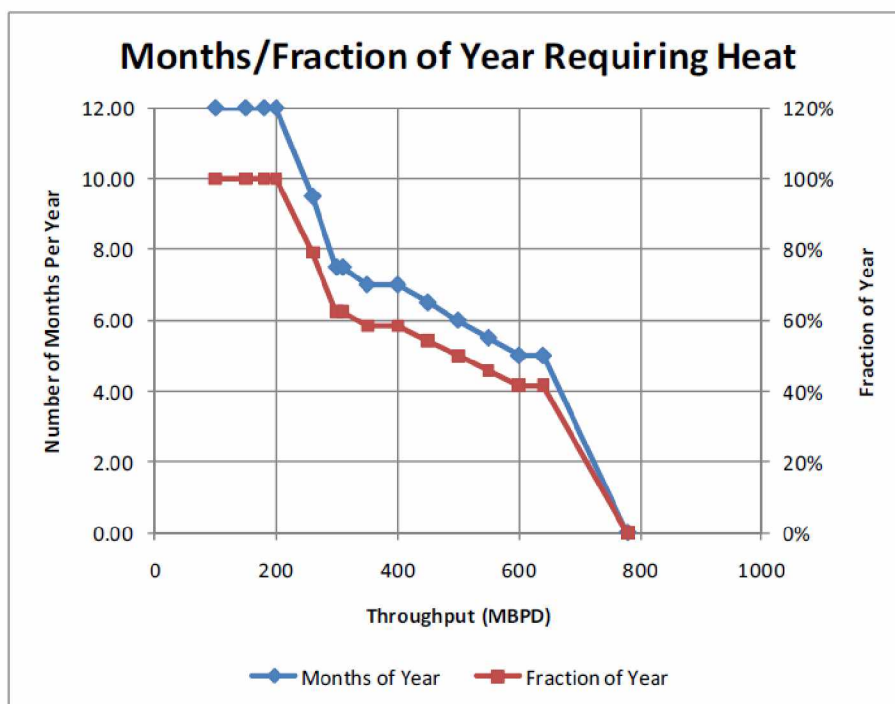


FIGURE 266: MONTHS OF THE YEAR REQUIRING HEAT UNDER LOW FLOW (BP PIPELINES ALASKA, INC, 2010)

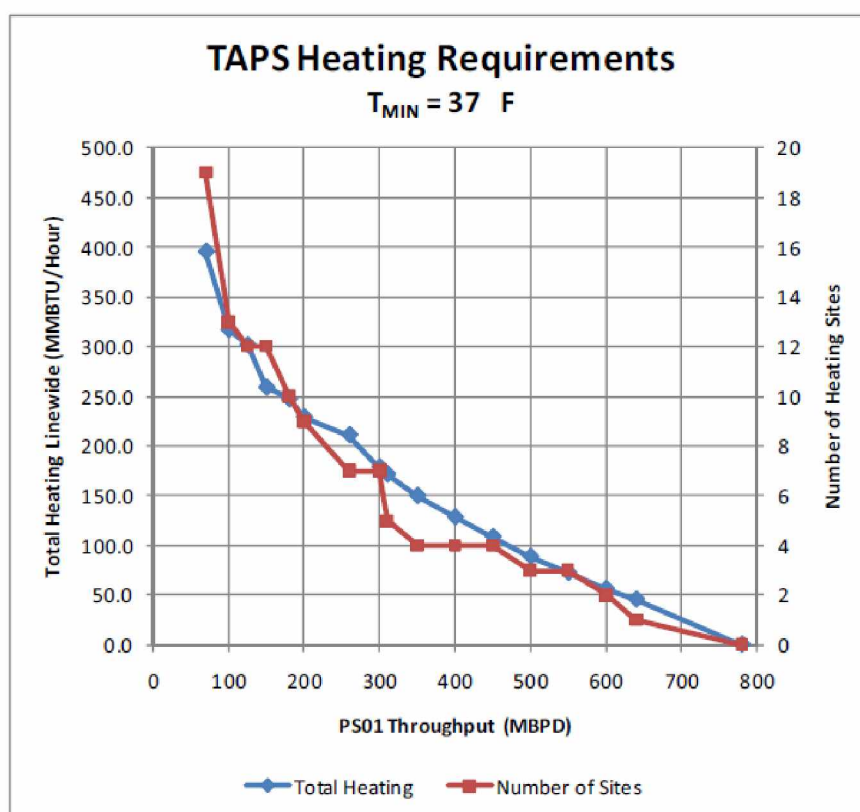


FIGURE 267: TAPS HEATING REQUIREMENT UNDER LOW FLOW (BP PIPELINES ALASKA, INC, 2010)

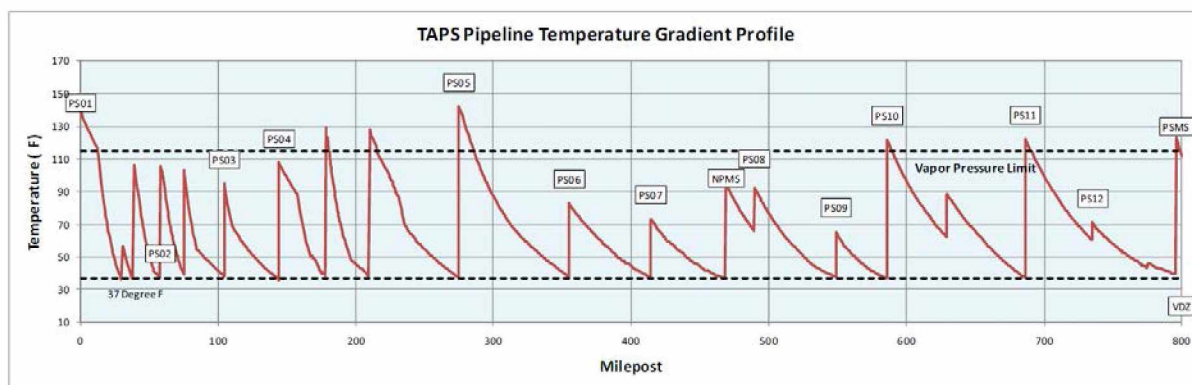


FIGURE 268: TAPS PIPELINE TEMPERATURE PROFILE AT 70,000 BOPD WITH HEAT (BP PIPELINES ALASKA, INC, 2010)

## 19. FUTURE ALASKA PRODUCTION

Forecasting Alaska North Slope production is complex due to the interactions between the different fields, changes in activity, differing levels of field maturity, and shared field constraints between anchor fields and their associated satellites. Examples of activity changes include Alpine, where drilling at CD5 increased production from 20,000 bopd to 50,000 bopd; Lisburne where a recent drilling campaign and other work helped increase production from 4,000-5,000 bopd to 13,000-15,000 bopd; Raven, a small pool where a sub 300 bopd well was sidetracked with over 1,000 bopd of benefit; and Tarn which arrested its decline and production from 5,000 bopd to a nearly flat 8,000 bopd. Some fields are currently experiencing negative decline as production is increasing in the Milne Sag and Milne Schrader pools, Nanuq, Northstar Kuparuk, and Oooguruk Nuiqsut. Nikaitchuq also appears to be just coming off plateau, complicating forecasts. Pt. Thomson has lacked plant reliability suitable for production forecasts. However, as seen in Figure 4, nearly half of the North Slope production comes from Prudhoe Bay, and around two thirds of North Slope production comes from Prudhoe Bay, Kuparuk, and Alpine; meaning small changes in decline rates in those fields have a larger impact in overall production forecasts than comparatively larger changes in the smaller fields. The larger uncertainty lies in future field developments, their first oil production dates, accuracy of predictions, and what remains left to be discovered. Due to the complexity of matching Prudhoe Bay's temperature dependant production history, a smoothed average production profile was used in estimating future production trends. Figure 437 and Figure 438 show that the forecasts used in this study incorporate a decline higher than those predicted by the Alaska Department of Revenue (DOR), however Figure 270 demonstrates that the DOR has a history of over predicting future production and assuming less decline than actually occurs.

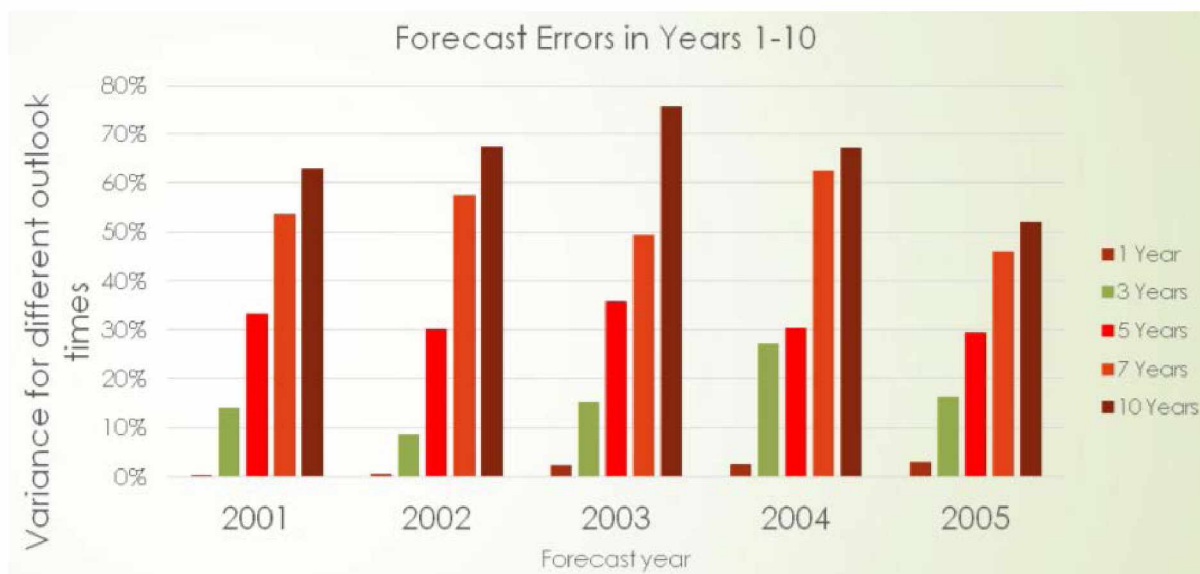


FIGURE 269: DOG FORECAST ERRORS IN YEARS 1-10 (UMEKWE, 2017)

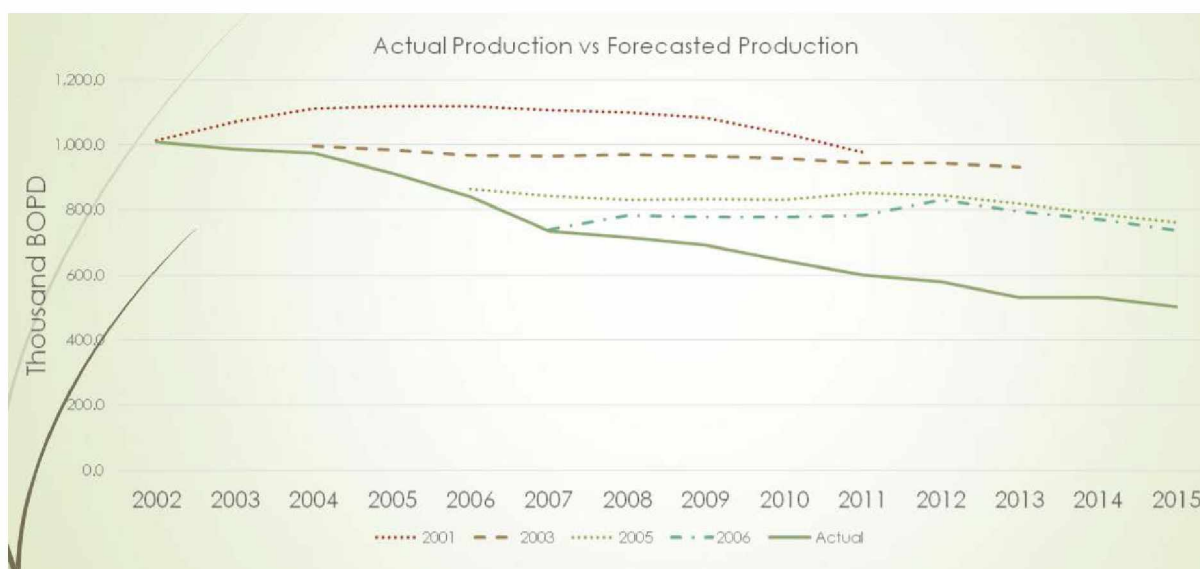


FIGURE 270: ACTUAL PRODUCTION VS. FORECASTED PRODUCTION (UMEKWE, 2017)

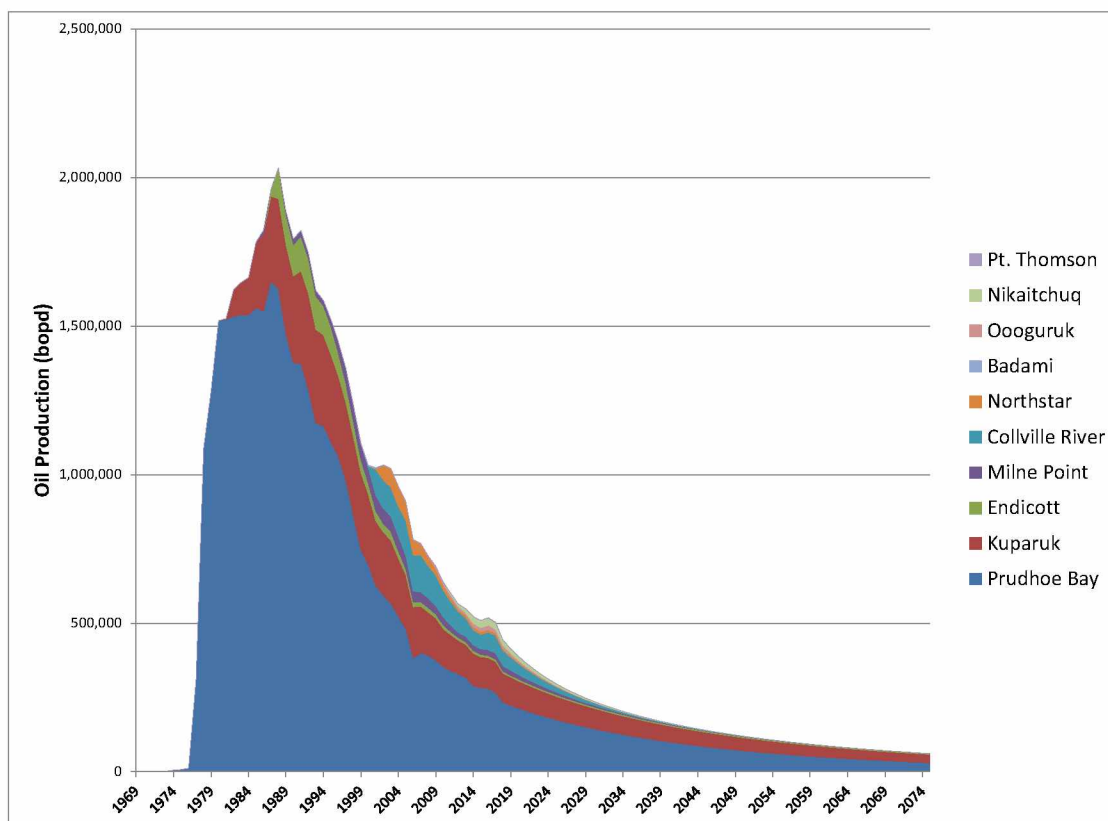


FIGURE 271: NORTH SLOPE EXISTING FIELD PRODUCTION AND FORECAST BY UNIT

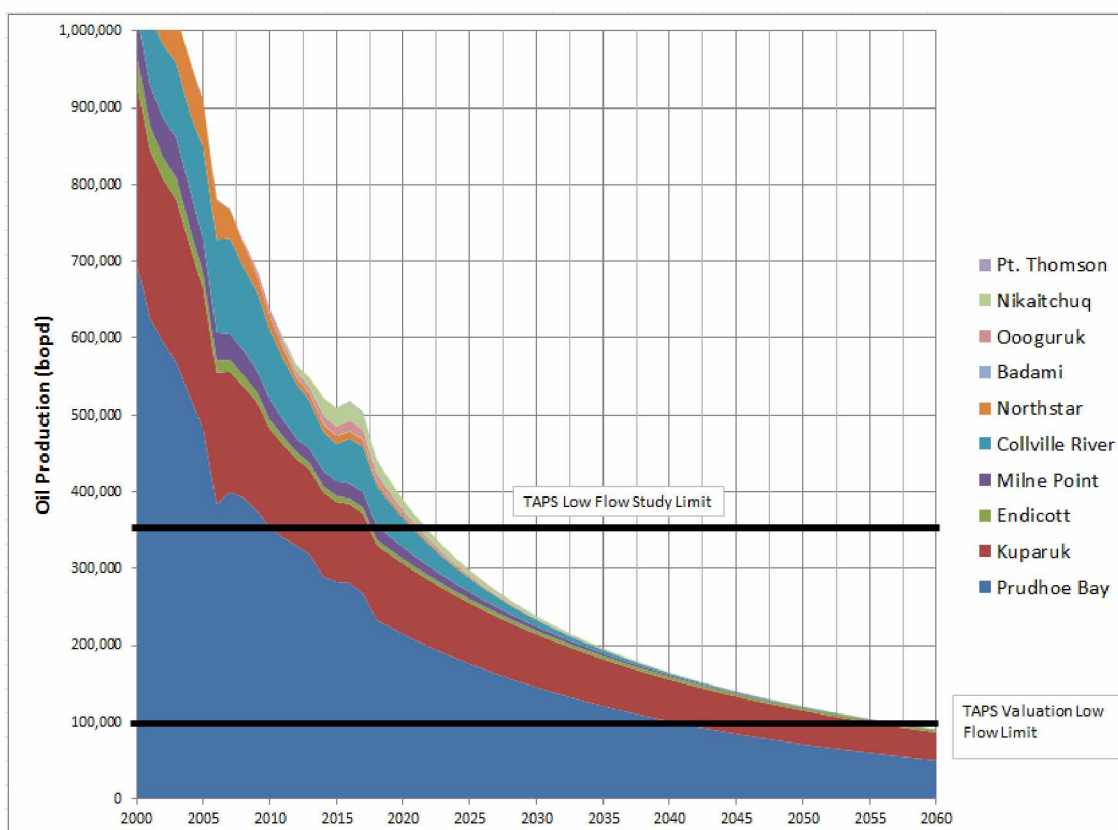


FIGURE 272: NORTH SLOPE FORECASTED PRODUCTION WITH LOW FLOW LIMITS HIGHLIGHTED

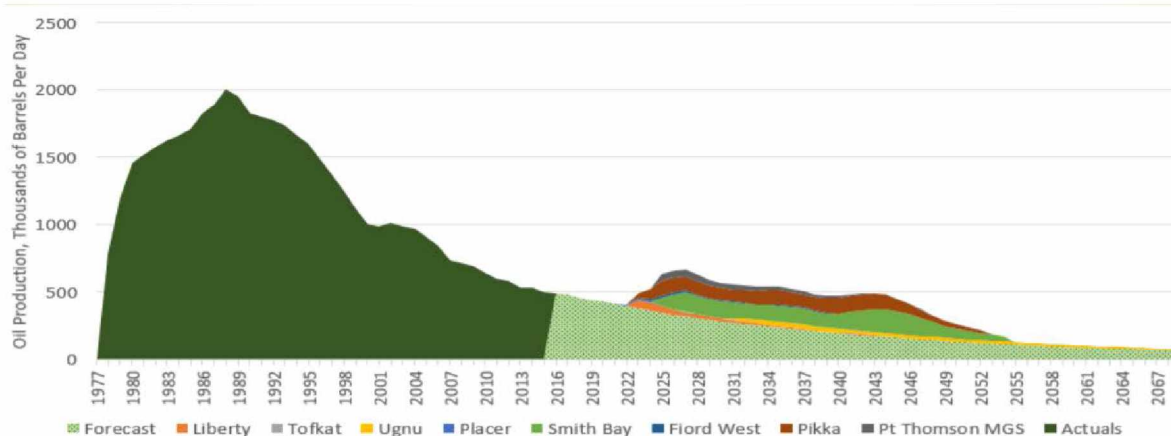


FIGURE 273: DIVISION OF OIL AND GAS FORECASTED RATES WITH PROJECTS (UMEKWE, 2017)

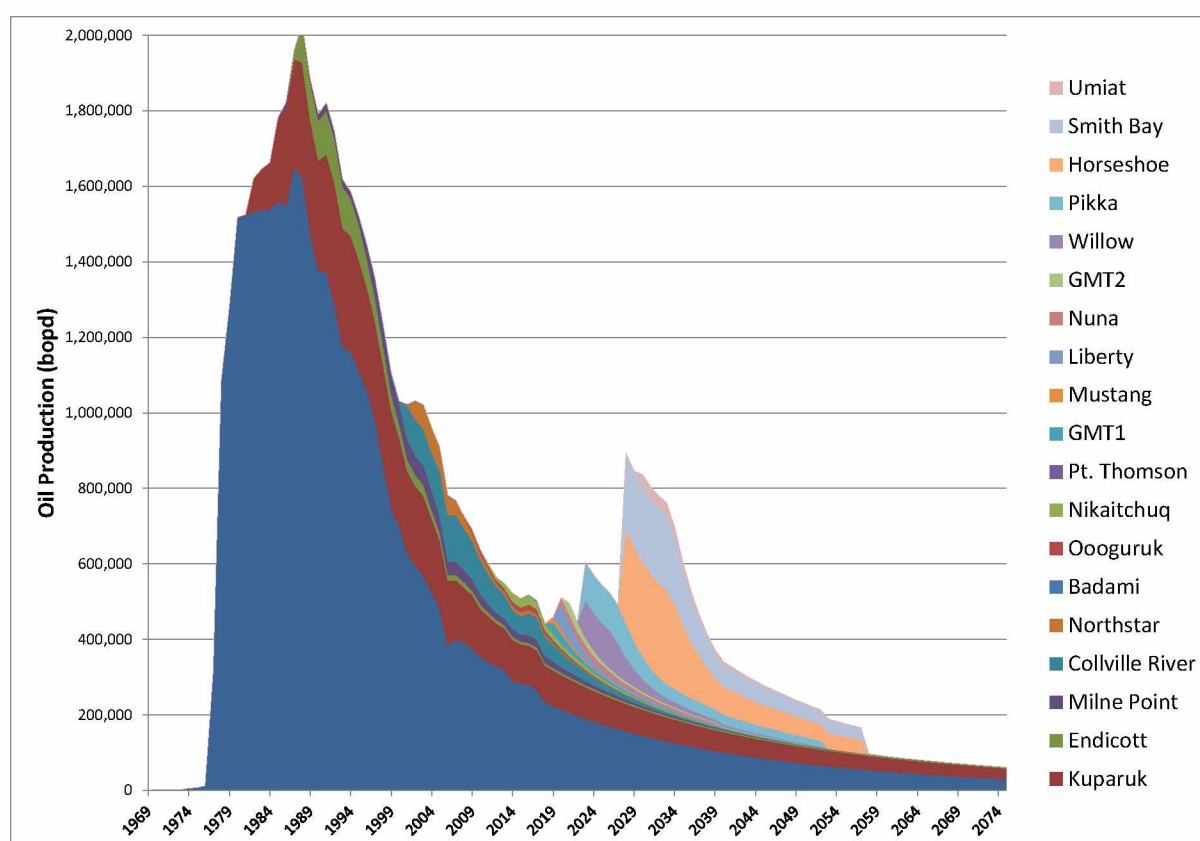


FIGURE 274: NORTH SLOPE FORECASTED PRODUCTION WITH EXPLORATION DEVELOPMENT

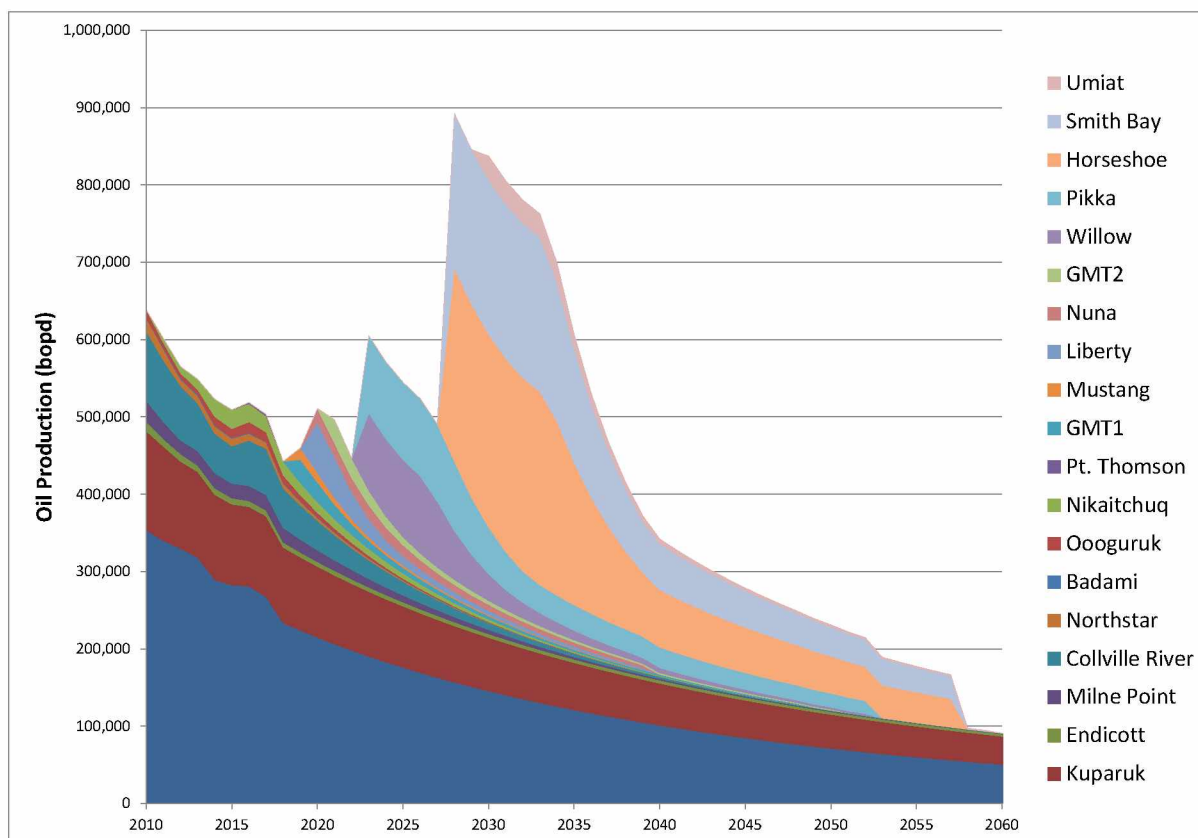


FIGURE 275: NORTH SLOPE FORECASTED PRODUCTION WITH EXPLORATION DEVELOPMENT 2010-2060

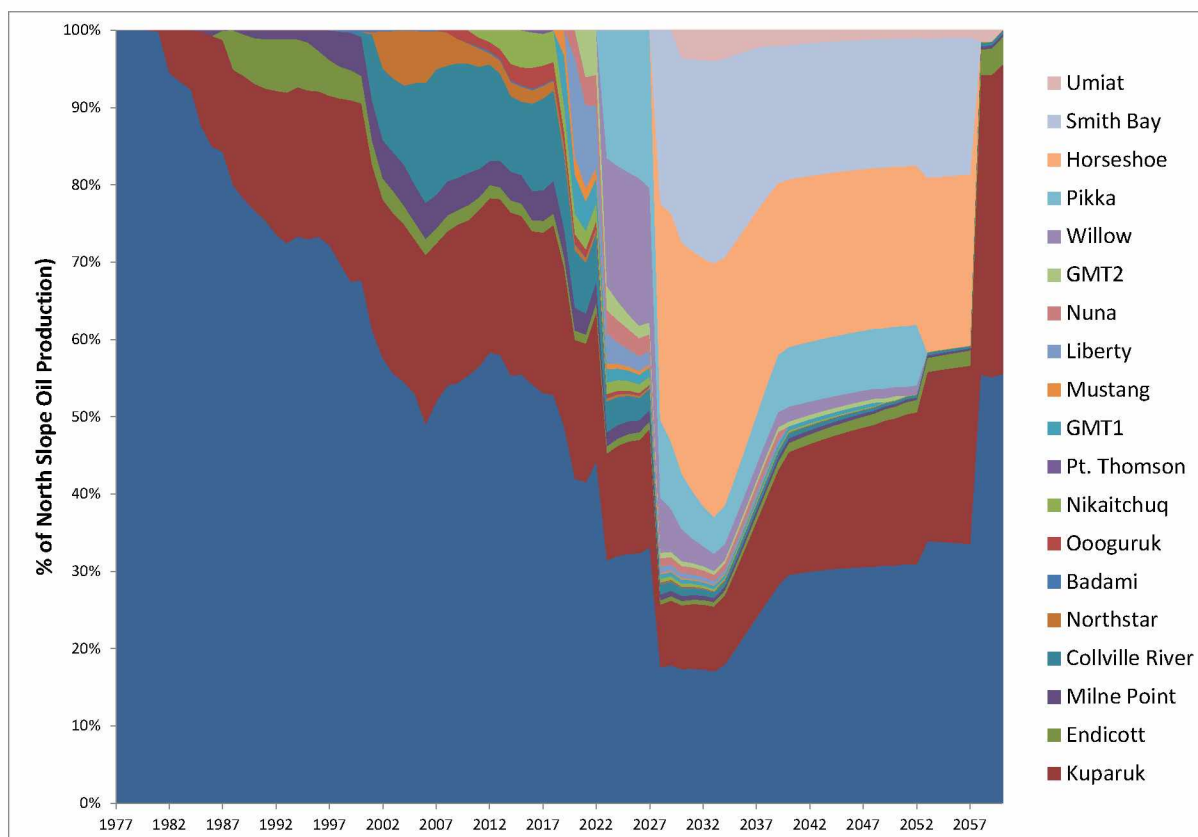


FIGURE 276: FORECASTED NORTH SLOPE PRODUCTION SOURCES DISTRIBUTION WITH EXPLORATION



## 20. ALASKA REVENUE FROM OIL

Alaska's petroleum tax code is complex, and changes often. The current tax code, the More Alaska Production Act, commonly referred to as Senate Bill 21 (SB21) is a 35% base tax with a series of optional credits. There are per barrel production credits, small operator credits, exploration credits, amongst others as well as eligible deductible expenses. To simplify estimation of petroleum tax revenue estimations for this study, Alaska Department of Revenue forecasts from Spring 2017 were compared to forecasted production, oil prices, and tax revenue to generate a correlation of approximately where tax revenue per taxable barrel is equal to  $0.0682x - 2.3727$ , where  $x$  is the oil price. This correlation may not hold true at higher oil prices when tax credits have a smaller influence. Petroleum property taxes, which average around \$100 million/year and corporate income taxes are not addressed here. It is unclear from the Department of Revenue published forecasts how petroleum corporate income taxes relate to production and price. Although there are some variances in lease royalty rates, the majority of North Slope production has a 12.5% state royalty rate, and that is used as an average for this analysis. In royalty valuation, wellhead value of oil is assumed to be 83% of oil price to account for midstream costs. As seen in Figure 279, the majority of the oil revenue is derived from royalties, and not the additional production tax. Although the amount of production tax increases with oil price, the value of the royalty barrels also increases. Overall, a 1% change in the price of oil results in about a 1.3% change in revenue. Although future production from year to year is generally stable and can be predicted within a margin of error of a few percent for near term forecasts, the price of oil is far more volatile. In Figure 277, the DOR forecast shows an increase in oil price greater than decline, resulting in overall increased revenue. Under flat, or only moderately increasing oil prices, revenue will continue to drop with decline.

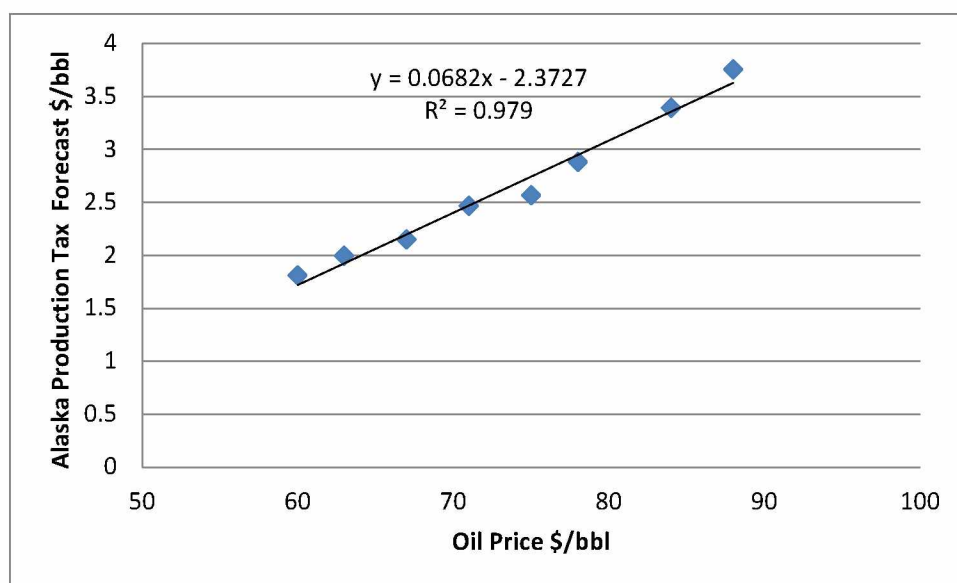


FIGURE 277: ALASKA PRODUCTION TAX ESTIMATION BASED ON DOR FORECASTS OF OIL PRICE AND REVENUE



FIGURE 278: STATE REVENUE BY OIL PRICE

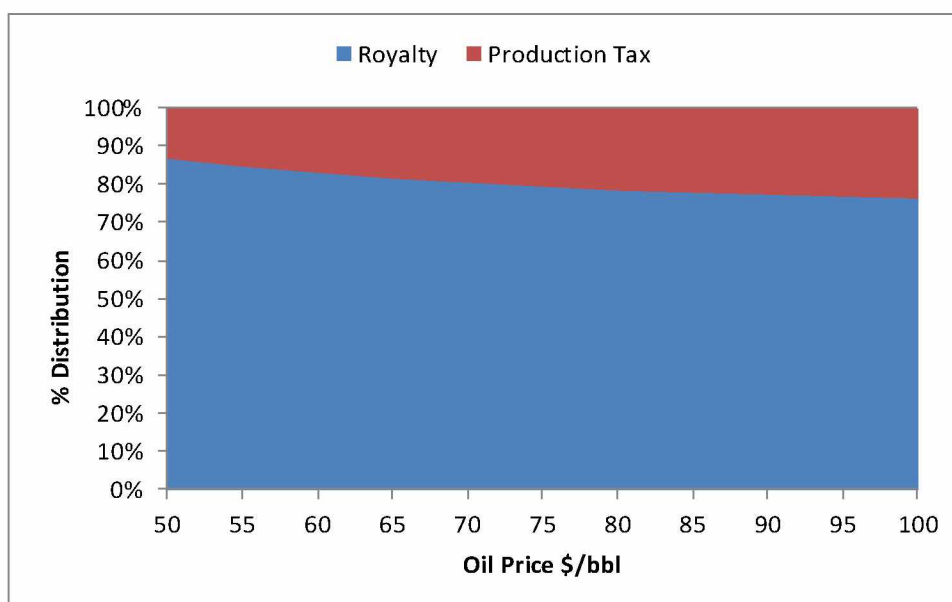


FIGURE 279: STATE REVENUE DISTRIBUTION BY OIL PRICE

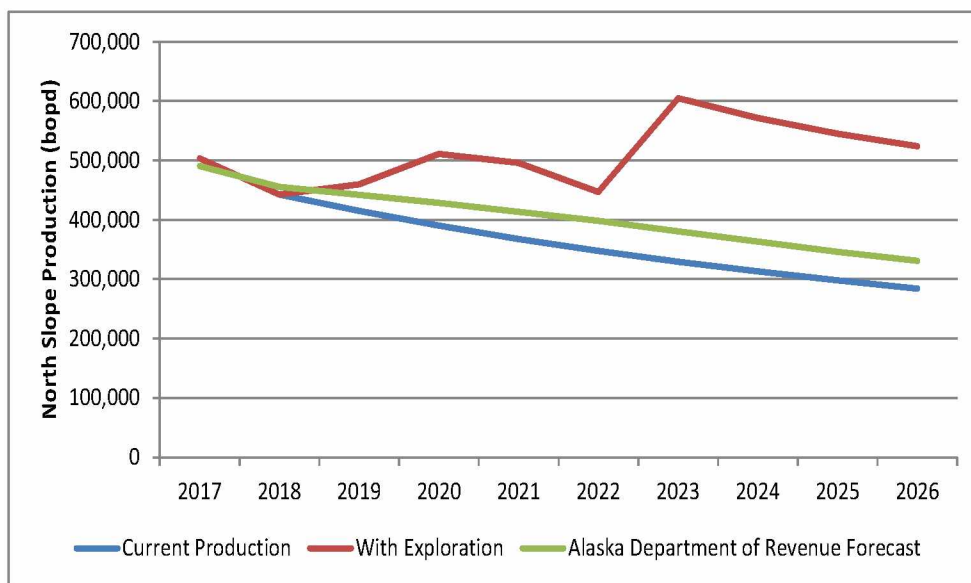


FIGURE 280: COMPARISON OF THE ALASKA DOR PRODUCTION FORECAST TO THE STUDY FORECAST

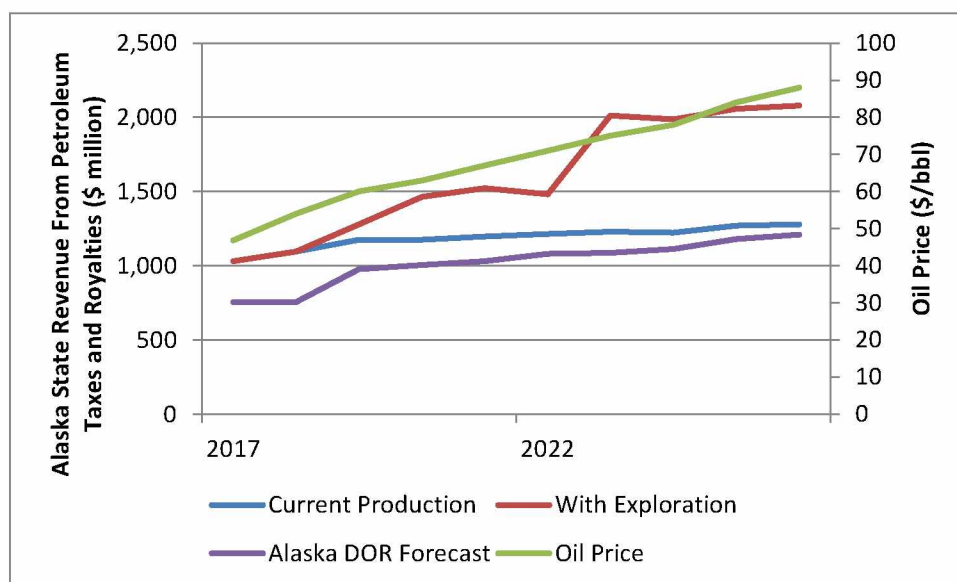


FIGURE 281: COMPARISON OF THE ALASKA DOR REVENUE 10 YEAR FORECAST TO THE STUDY FORECAST

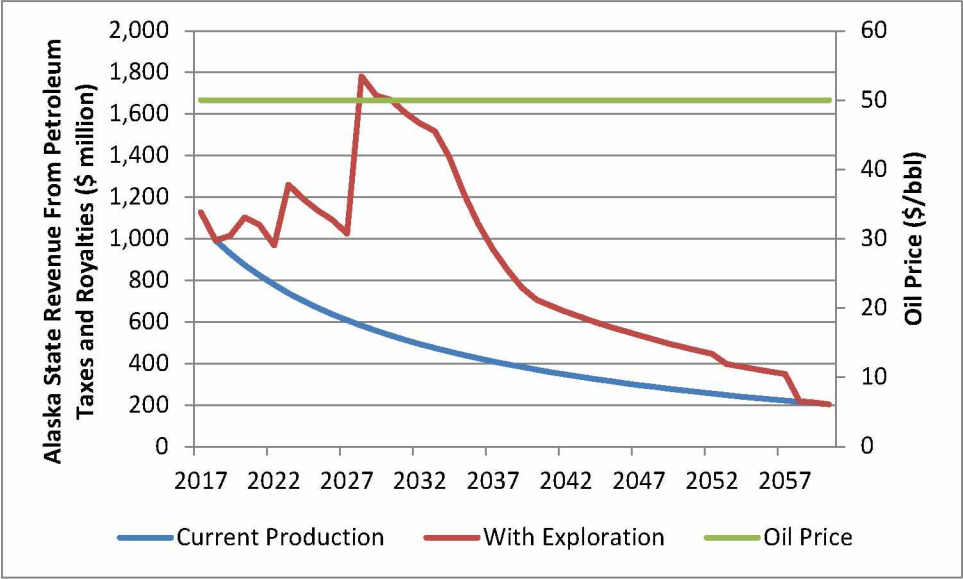


FIGURE 282: FORECASTED ALASKA STATE REVENUE FROM PETROLEUM TAXES AND ROYALTIES, \$50/BBL

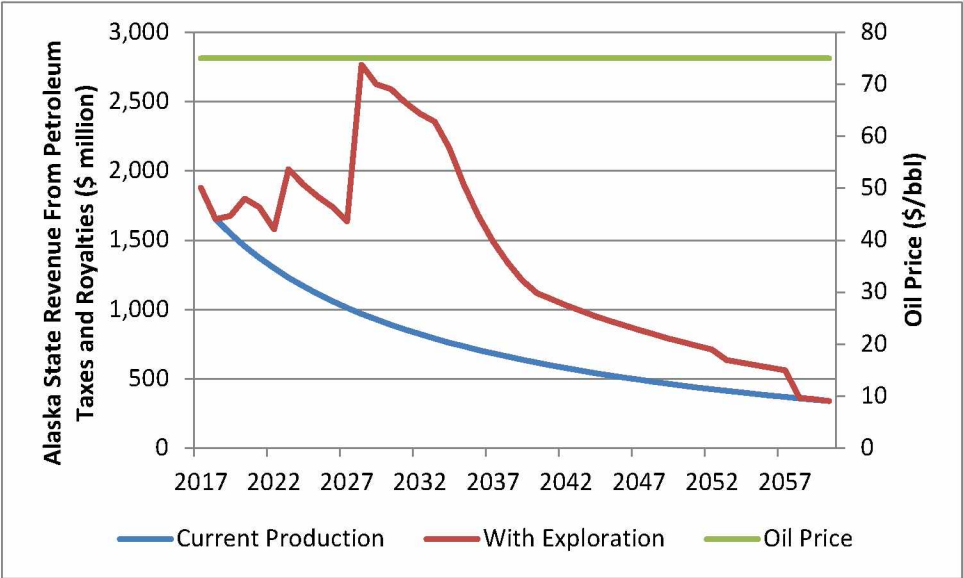


FIGURE 283: FORECASTED ALASKA STATE REVENUE FROM PETROLEUM TAXES AND ROYALTIES, \$75/BBL

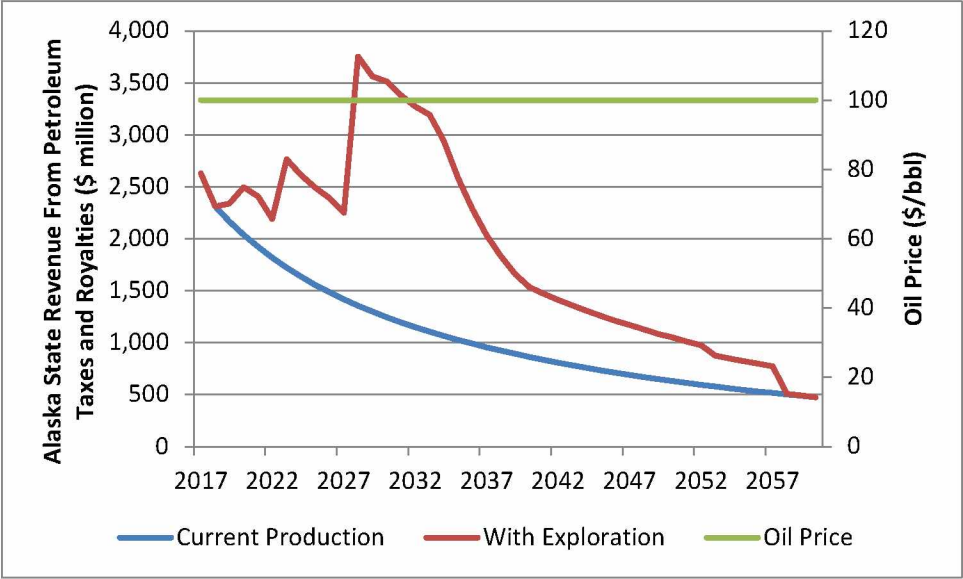


FIGURE 284: FORECASTED ALASKA STATE REVENUE FROM PETROLEUM TAXES AND ROYALTIES, \$100/BBL

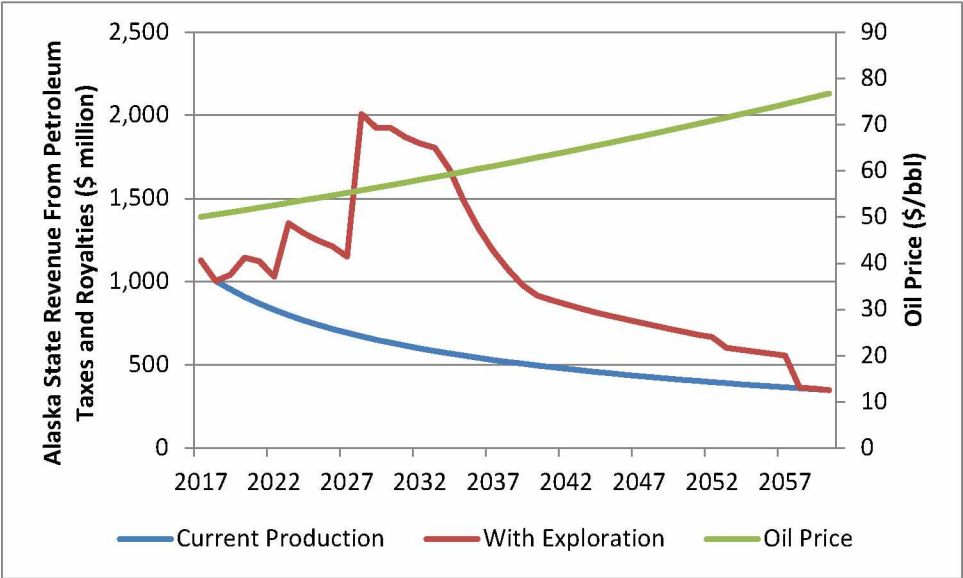


FIGURE 285: FORECASTED ALASKA STATE REVENUE FROM PETROLEUM TAXES AND ROYALTIES, \$50/BBL A 1%/YEAR INCREASE IN OIL PRICE



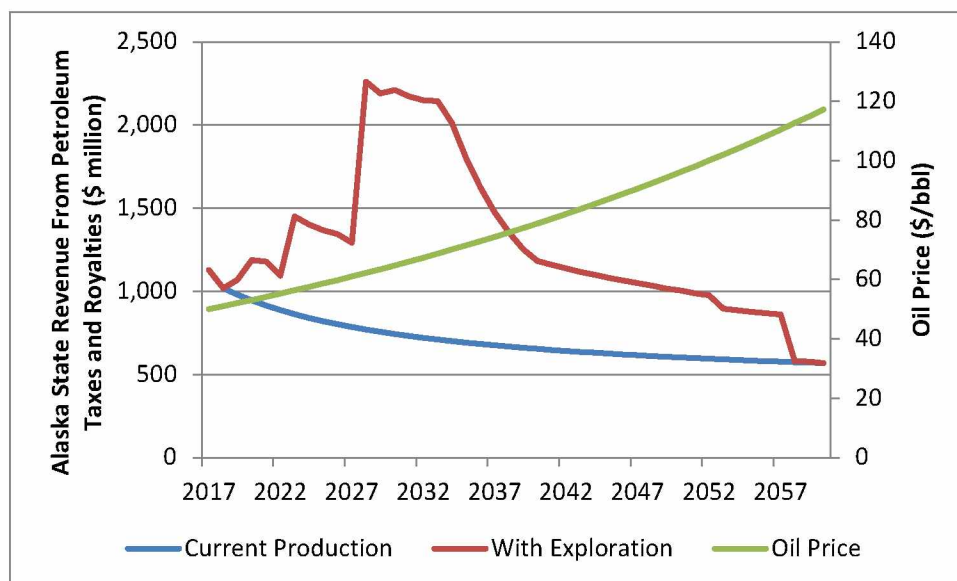


FIGURE 286: FORECASTED ALASKA STATE REVENUE FROM PETROLEUM TAXES AND ROYALTIES, \$50/BBL WITH A 2%/YEAR INCREASE IN OIL PRICE

TABLE 17: ROYALTY + TAX REVENUE OF PROJECT FORECAST UNDER SELECTED PRICE PATHS (ALASKA DEPARTMENT OF REVENUE, 2018)

	Year, Price per Barrel in \$, Royalty + Tax Revenue in \$ millions								
	2019	2020	2021	2022	2023	2024	2025	2026	2027
<b>DOR Spring 2018 Official</b>									
Price Per Barrel	63	64	66	67	69	70	72	74	75
Royalty + Tax Revenue	1251	1199	1174	1131	1111	1074	1058	1043	1012
<b>NYMEX Futures</b>									
Price Per Barrel	62	59	57	56	56	56	56	56	
Royalty + Tax Revenue	1226	1083	977	903	856	813	774	738	
<b>EIA STEO</b>									
Price Per Barrel	60								
Royalty + Tax Revenue	1176								
<b>EIA AEO Base/Reference</b>									
Price Per Barrel		67	80	88	93	98	102	106	110
Royalty + Tax Revenue		1269	1481	1567	1583	1597	1591	1585	1578
<b>Analysts Average</b>									
Price Per Barrel	64	66	67	64					
Royalty + Tax Revenue	1275	1245	1196	1069					

## 21. CONCLUSIONS

Central North Slope fields have sufficient history and similar attributes that future developments can use existing fields as analogs to make predictions. This is aided by many of the fields sharing the same source rocks, and being produced out of a small number of regionally extensive formations. New developments, farther away from existing developments should have a large prolific anchor field, as smaller satellite sized accumulations historically cannot deliver adequate rate. After 40 years of production, Prudhoe Bay still is the dominant field on the North Slope, accounting for 45% of current production, and acts as an anchor field for all others. Relatively large changes in the non-anchor field pools are only able to change North Slope production by a couple of percent due to the nature of their size compared to Prudhoe Bay, Kuparuk and Alpine, although they may be economic within their own development. New developments however, are able to materially contribute to changes in North Slope production if they are large enough. With continued activity in the many fields, creating an accurate forecast is challenging, although the overall trend of the North Slope is still a steady decline. Without new developments, the Trans Alaska Pipeline will need to make changes to accommodate low flow rates in the next ten years. Currently identified new developments have the potential to extend current production rates 10-20 years, assuming they deliver as anticipated on the project schedules announced. Some of these announced developments and discoveries have announced productivity rates that are not realistic compared to analog well performance, and will likely require many more wells to achieve the announced rates and volumes, which negatively affects the economics of the developments. The Alaska Department of Revenue's forecasts for state revenue assumes minimal production decline the average decline and a steady increase in oil prices of about 5% per year, the first of which is unlikely to occur without new developments coming online to offset decline and the later could be considered an optimistic price forecast. New and large North Slope developments are critical to continue the operation of TAPS, and revenue to the State of Alaska.

APPENDIX

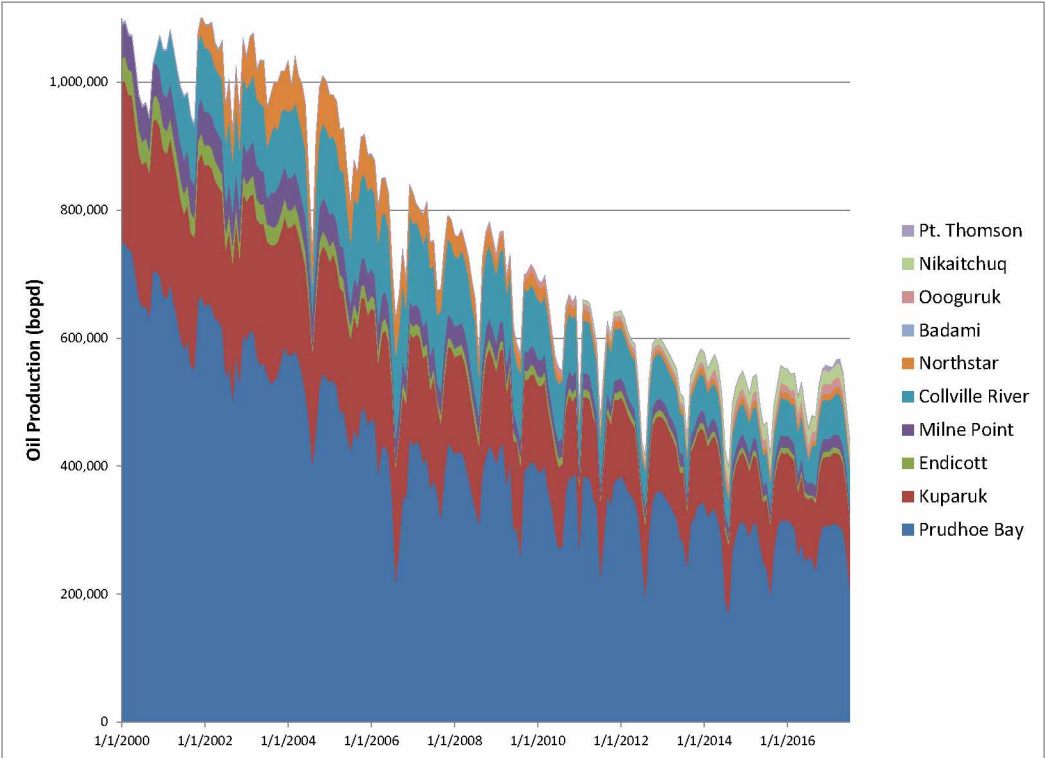


FIGURE 287: RECENT NORTH SLOPE PRODUCTION BY UNIT

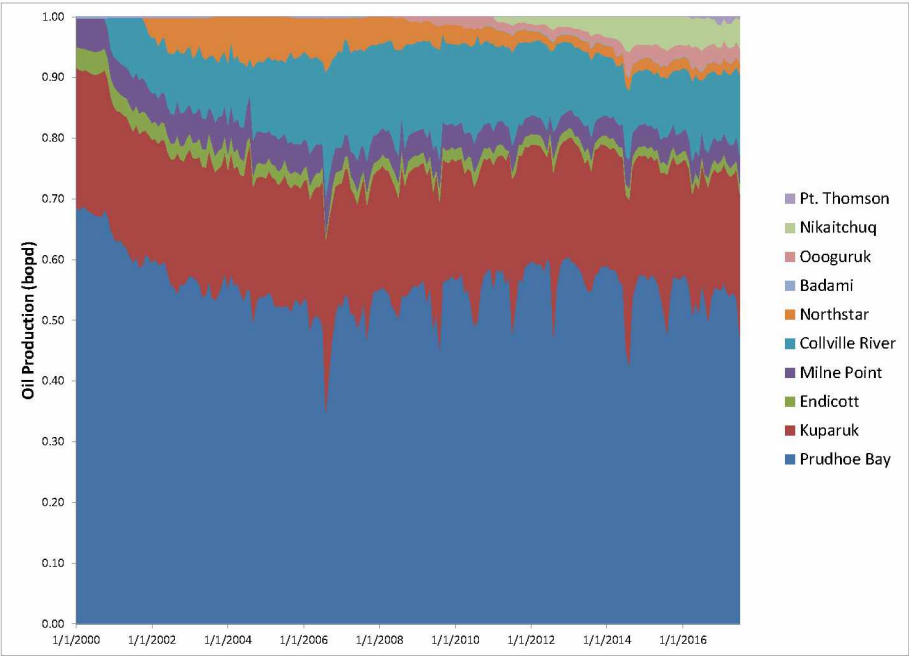


FIGURE 288: RECENT PERCENTAGE OF NORTH SLOPE PRODUCTION BY UNIT

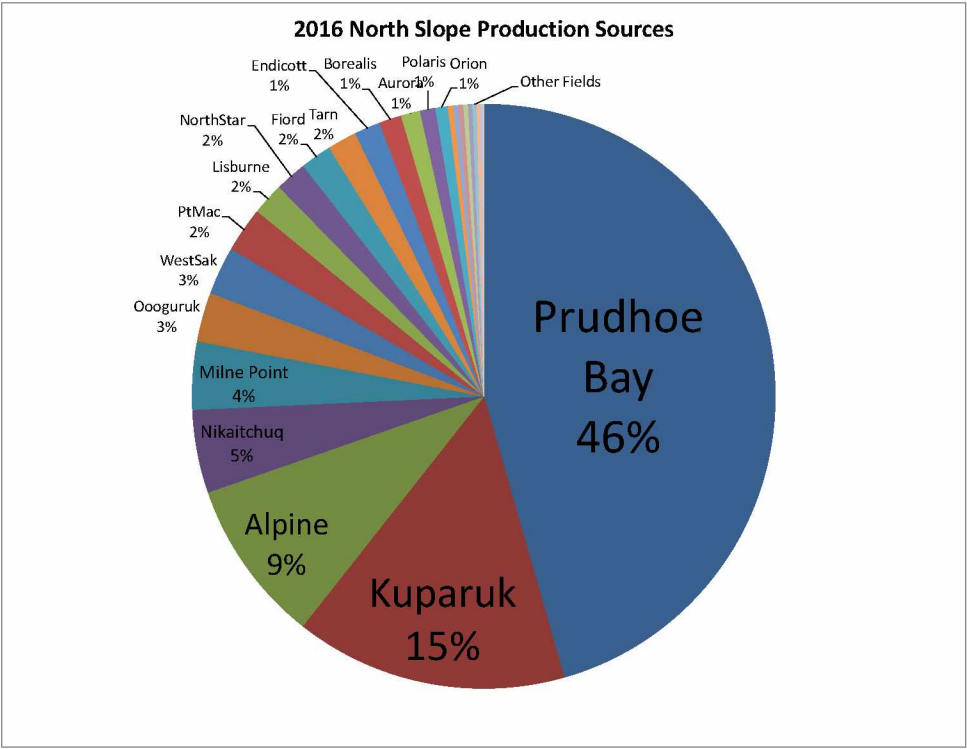


FIGURE 289 2016 NORTH SLOPE PRODUCTION SOURCES BY FIELD

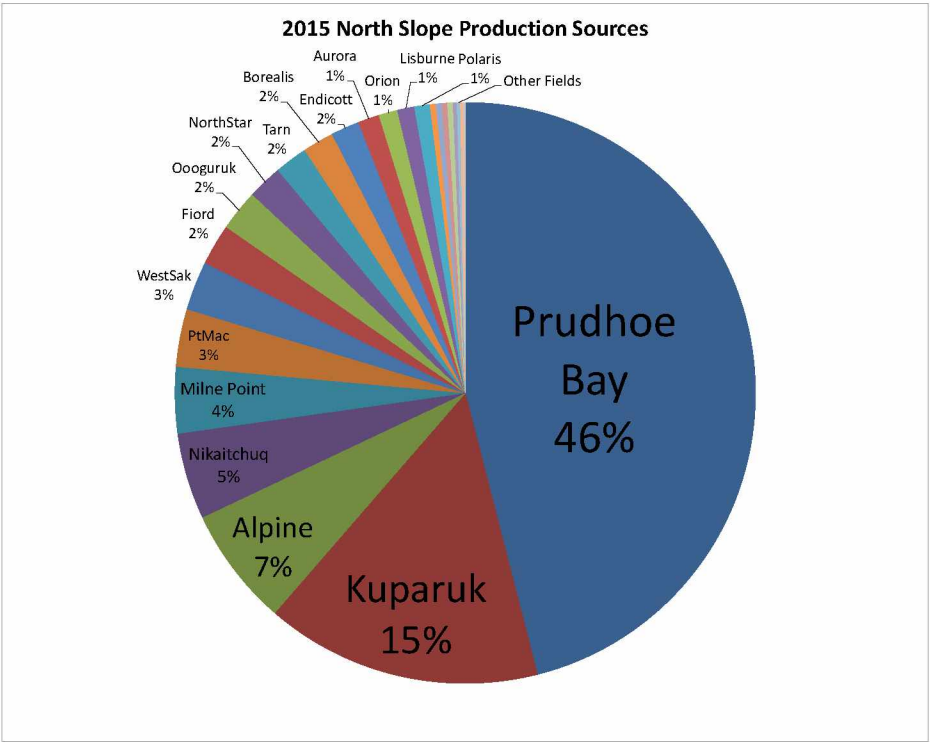


FIGURE 290: 2015 NORTH SLOPE PRODUCTION SOURCES BY FIELD

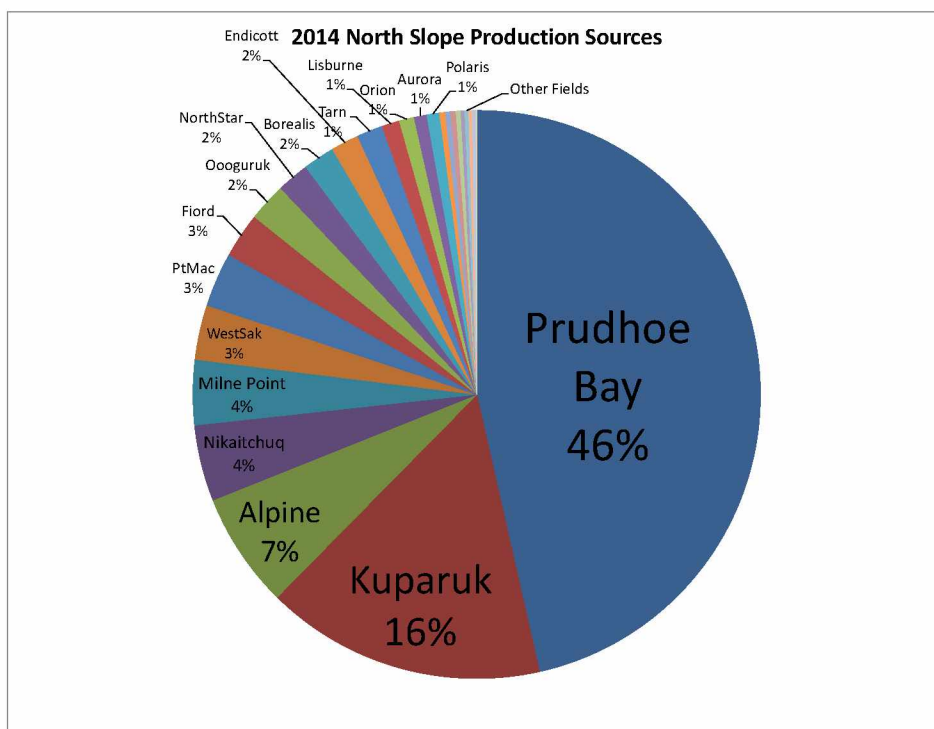


FIGURE 291: 2014 NORTH SLOPE PRODUCTION SOURCES BY FIELD

TABLE 18: SELECTED RESERVOIR PROPERTIES

Field	Reference Datum (TVDSS)	Oil Viscosity @ Original		Oil Gravity (°API)	Permeability (mD)	Net Pay (ft)	KH/μ
		Pressure (cp)					
Badami (oil)	10500	0		30.5	200.5	0	
Alpine	7000	0.46		40	500.5	48	52226
Fiord	6850	0.97		29	59	22.5	1369
Nanuq	6150	0.5		40	2.5	35	175
Nanuq_Kuparuk	7000	0.69		40	100	6	870
Qannik	4000	2		29	13	12	78
Eider	9700	0		25	134	0	
Endicott	10000	0		23	675	0	
Sag Delta North	10000	0		25	301	0	
Minke	9800	0.14		25	185	84	111000
Kuparuk	6200	2.2		24	150	100	6818
Meltwater	5400	0.75		36	10	95	1267
Tabasco	3100	251		16.5	5500	132	2892
Tarn	5200	0.55		37	10	90	1636
West Sak	3500	42		19	1007.5	70	1679
Milne_Kuparuk	7000	4.35		23	55	32.5	411
Milne_Sag	8700	0.33		34.4	13.5	31.5	1289
Milne_Schrader	4000	120		18	1550	30	388
Milne_Ugnu	3500	10500		11.5	2500	75	18
Nikaitchuq	3760	143		17.5	300	32.5	68
Northstar	11100	0.14		44	188	105	141000
Oooguruk_Kuparuk	6050	2		24.5	75	30	1125
Oooguruk_Nuiqsut	6350	5.5		22	3.1	75	42
Oooguruk_Torok	5000	4		24	4	70	70
Aurora	6700	0.72		27.5	105	60	8750
Borealis	6600	2.3		25.25	150.5	60	3926
Lisburne	8900	0.9		27	1.05	125	146
Midnight Sun	8050	1.68		27	780.5	35	16260
North Prudhoe	9245	0.425		35	590	20	27765
Niakuk	9200	0.94		24.9	500	105	55851
Orion	4400	69.5		18.5	705	110	1116
Polaris	5000	62.5		20	905	67.5	977
Prudhoe	8800	0.81		28	265	200	65432
Pt. McIntyre	8800	0.9		27	200	156	34667
West Beach	8800	1.04		25.7	107	71	7305



TABLE 19: SELECTED FIELD DYNAMICS

Field	Cum Total Oil	Average Producer:Injector Ratio	Total Wells	Active Wells	Cum Oil/Lifetime Wells	Cum Oil/Active Producer Profile
Badami (oil)	7.30	7	10	9	0.73	1.34
Alpine	443.90	1	166	156	2.67	11.39
Fiord	66.21	1.35	34	29	1.95	7.13
Nanuq	3.75	1.5	12	10	0.31	1.11
Nanuq_Kuparuk						
Qannik	6.01	2	9	9	0.67	1.16
Eider	2.83	1	2	1	1.41	2.56
Endicott	497.72	2.5	129	103	3.86	10.04
Sag Delta North	8.91	1	5	4	1.78	4.47
Minke	1.38		1	1	1.38	1.45
Kuparuk	2409.91	1.3	1112	965	2.17	7.73
Meltwater	19.38	2.2	19	19	1.02	2.33
Tabasco	19.65	5.1	12	12	1.64	3.54
Tarn	118.79	2	77	68	1.54	5.20
West Sak	84.34	1.3	141	121	0.60	2.56
Milne_Kuparuk	255.26	1.8	204	179	1.25	4.36
Milne_Sag	2.94	2	9	7	0.33	1.87
Milne_Schrader	77.61	1	159	133	0.49	2.46
Milne_Ugnu	0.12		6	6	0.02	0.11
Nikaitchuq	35.72	1.3	51	51	0.70	1.79
Northstar	166.85	2.6	29	27	5.75	13.90
Oooguruk_Kuparuk	8.50	1.6	8	7	1.06	3.33
Oooguruk_Nuiqsut	19.01	2.1	31	31	0.61	2.12
Oooguruk_Torok	0.84	2	4	4	0.21	0.59
Aurora	42.61	1.5	40	36	1.07	3.89
Borealis	81.68	1.5	56	54	1.46	3.86
Lisburne	187.56	9.5	100	86	1.88	5.75
Midnight Sun	21.03	0.65	6	6	3.51	13.27
North Prudhoe	2.07		1	1	2.07	1.99
Niakuk	96.05	2	35	24	2.74	8.39
Orion	34.33	0.5	48	47	0.72	5.43
Polaris	21.03	0.5	29	28	0.73	3.34
Prudhoe	12397.39	3.3	2599	1378	4.77	34.98
Pt. McIntyre	477.28	2.9	93	77	5.13	14.01
West Beach	3.59		3	3	1.20	2.95
Pt. Thomson	0.47	0.5	2	2	0.24	1.27
Badami_undef	0.45		0	0		0.48
PutRiver	3.01		3	3	1.00	2.40
Raven	3.53	1.3	6	5	0.59	2.34
Northstar_Kuparuk	3.13		2	2	1.57	2.95

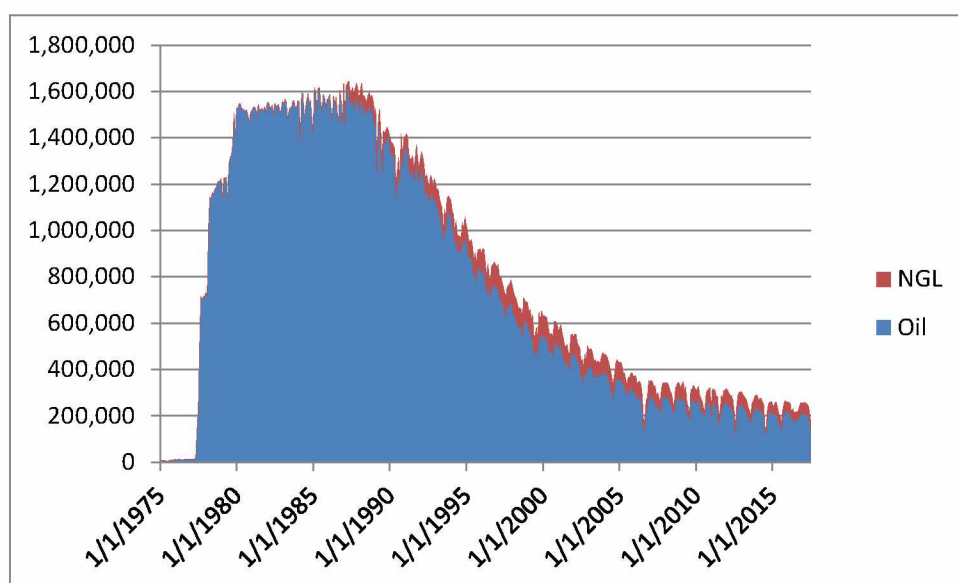


FIGURE 292: PRUDHOE BAY OIL AND NGL PRODUCTION

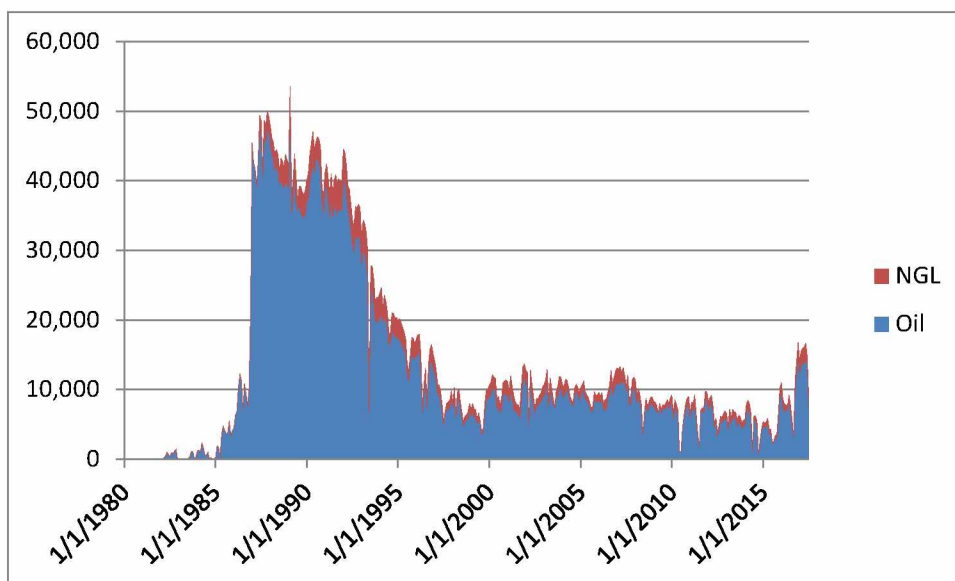


FIGURE 293: LISBURNE OIL AND NGL PRODUCTION

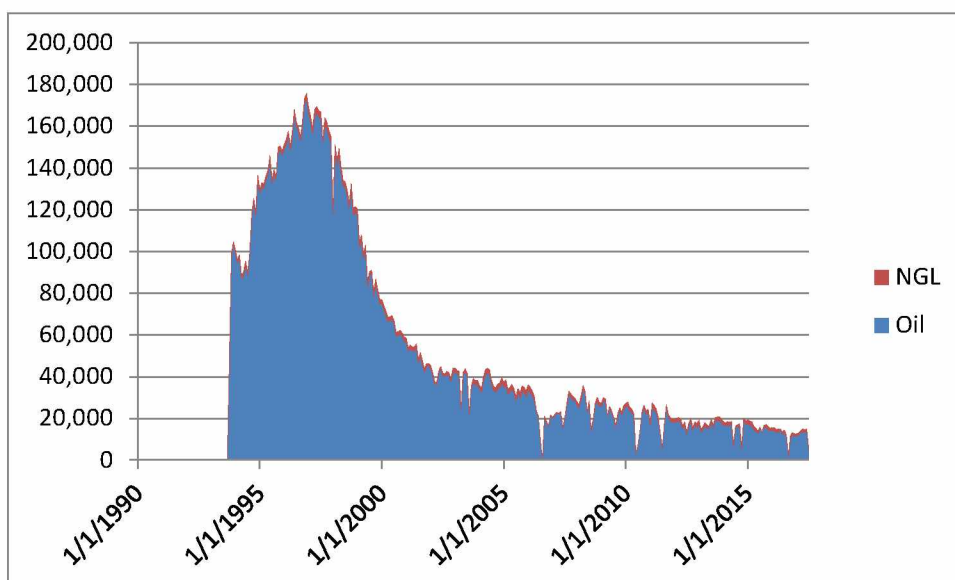


FIGURE 294: PT. MCINTYRE OIL AND NGL PRODUCTION

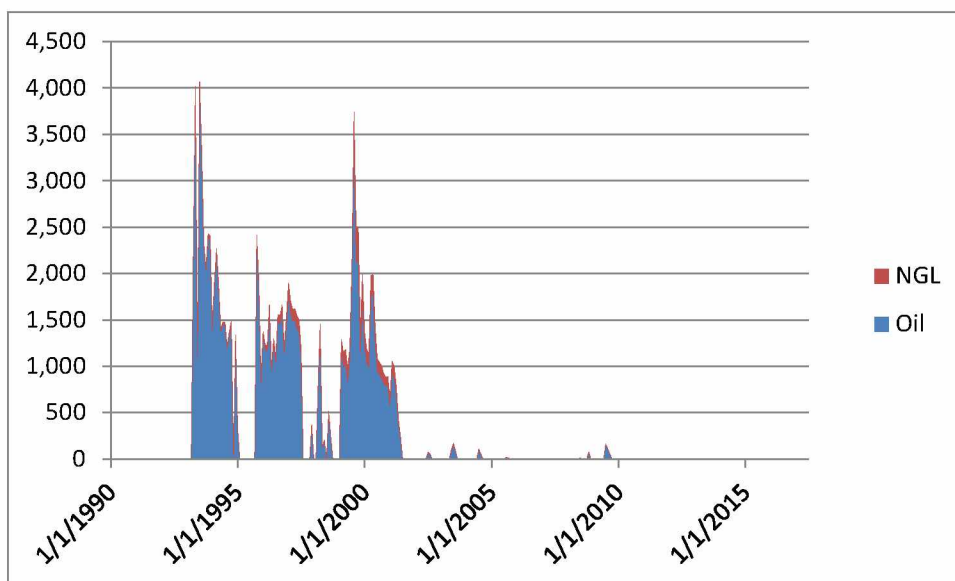


FIGURE 295: WEST BEACH OIL AND NGL PRODUCTION

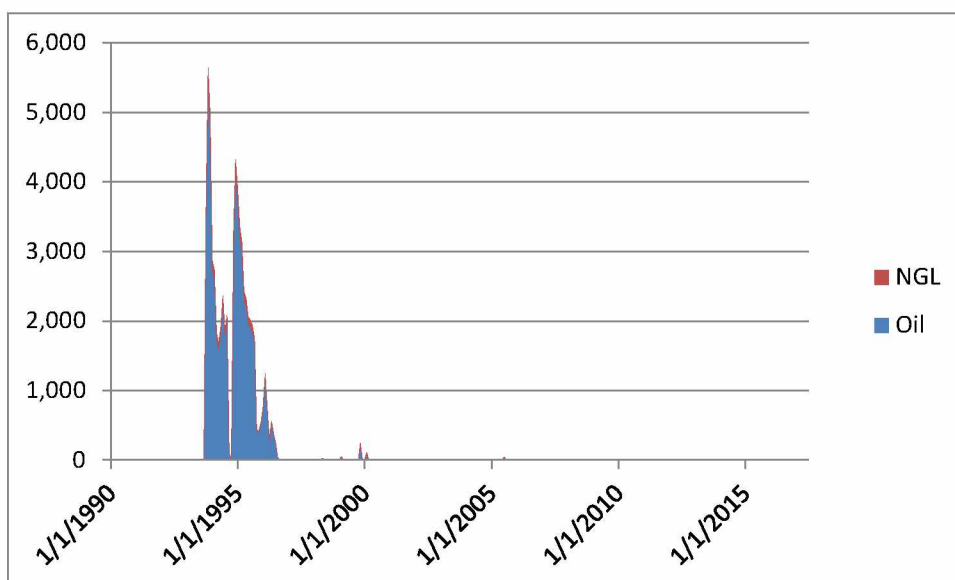


FIGURE 296: NORTH PRUDHOE OIL AND NGL PRODUCTION

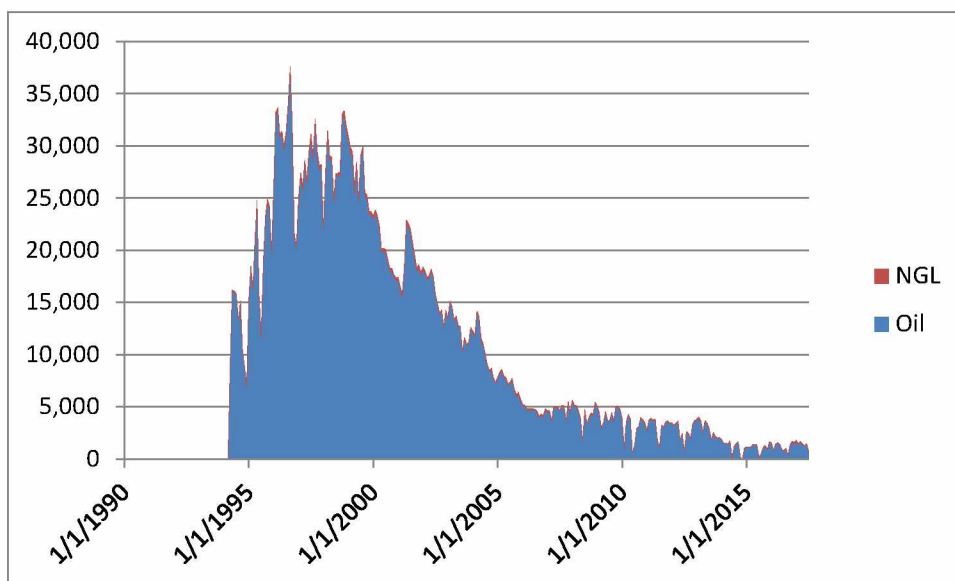


FIGURE 297: NIAKUK OIL AND NGL PRODUCTION

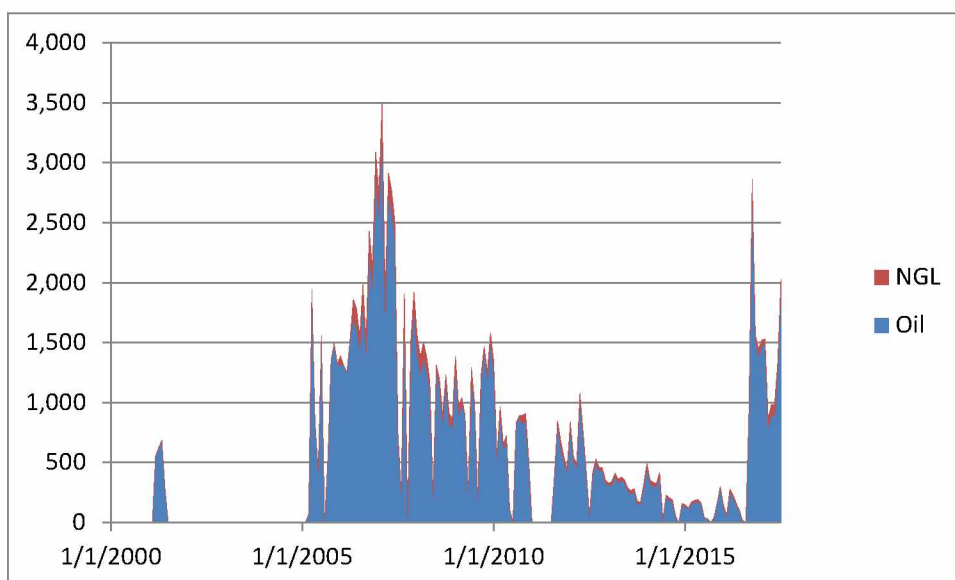


FIGURE 298: RAVEN OIL AND NGL PRODUCTION

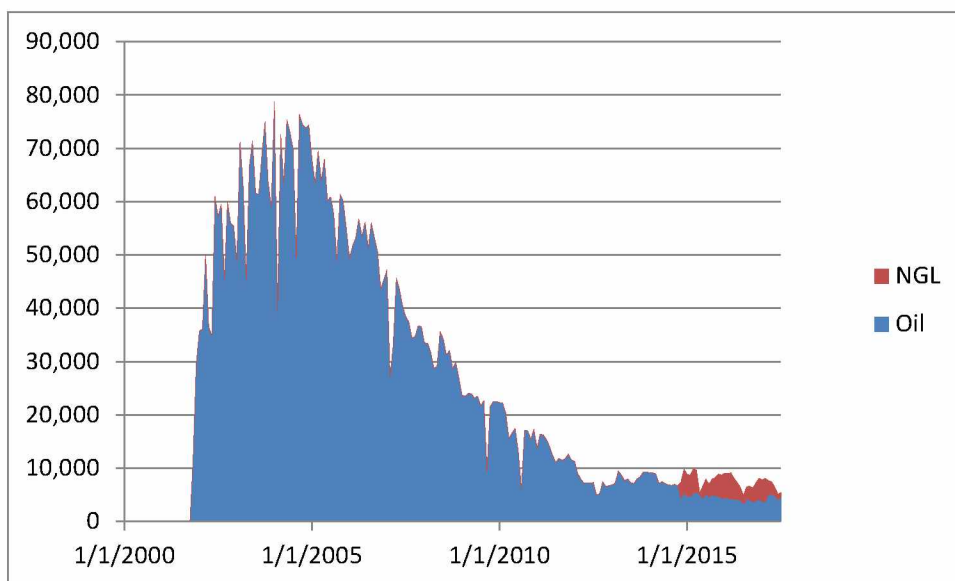


FIGURE 299: NORTHSTAR OIL AND NGL PRODUCTION

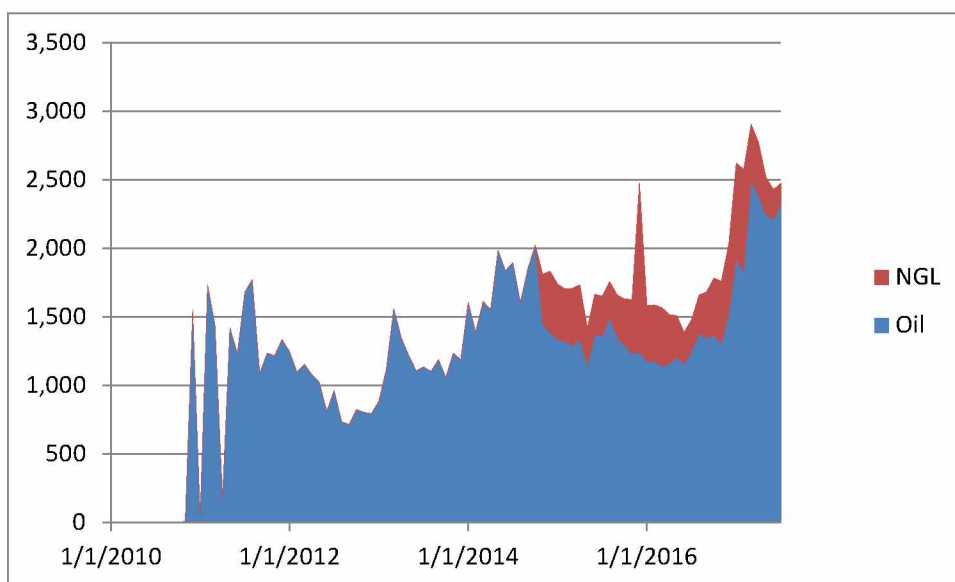


FIGURE 300: NORTHSTAR KUPARUK OIL AND NGL PRODUCTION

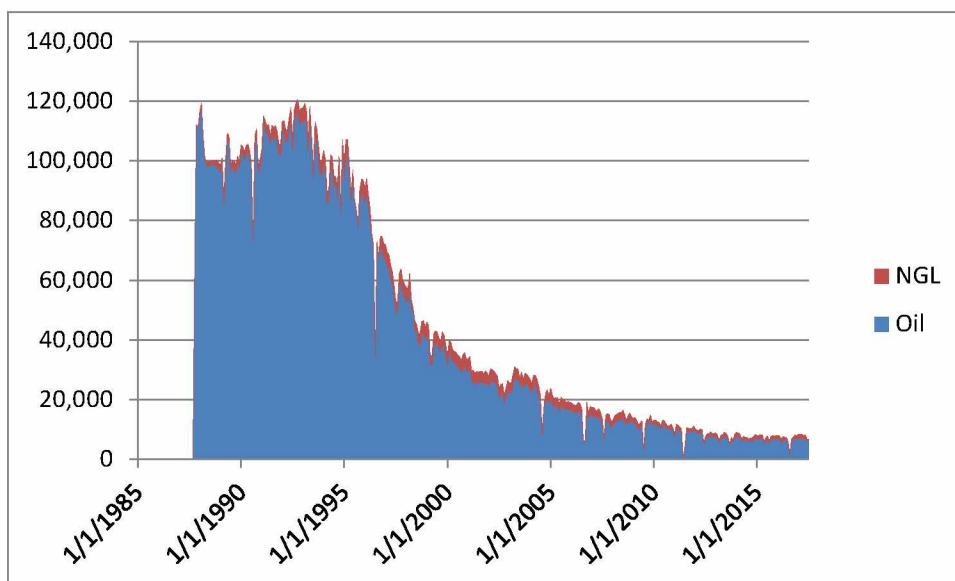


FIGURE 301: ENDICOTT OIL AND NGL PRODUCTION

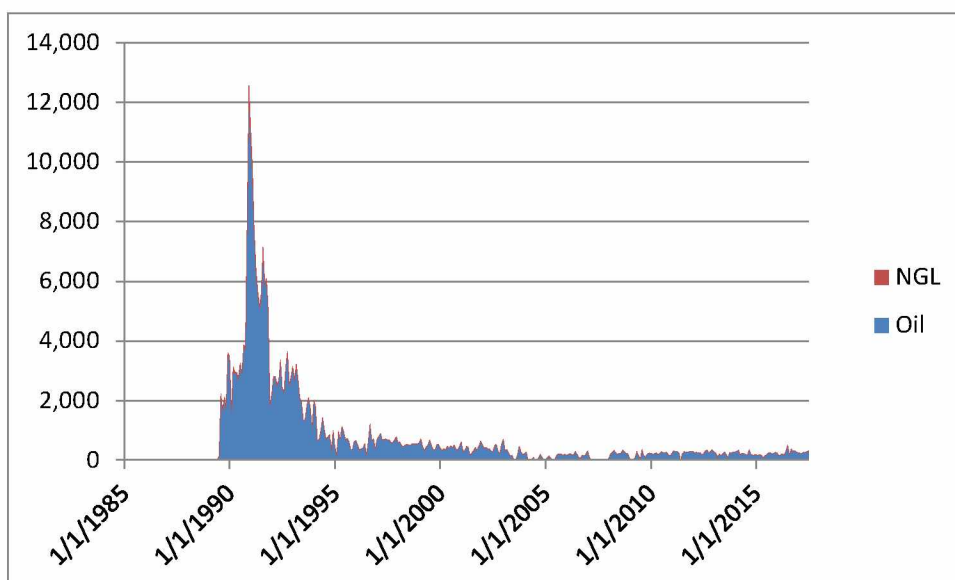


FIGURE 302: SAG DELTA NORTH OIL AND NGL PRODUCTION



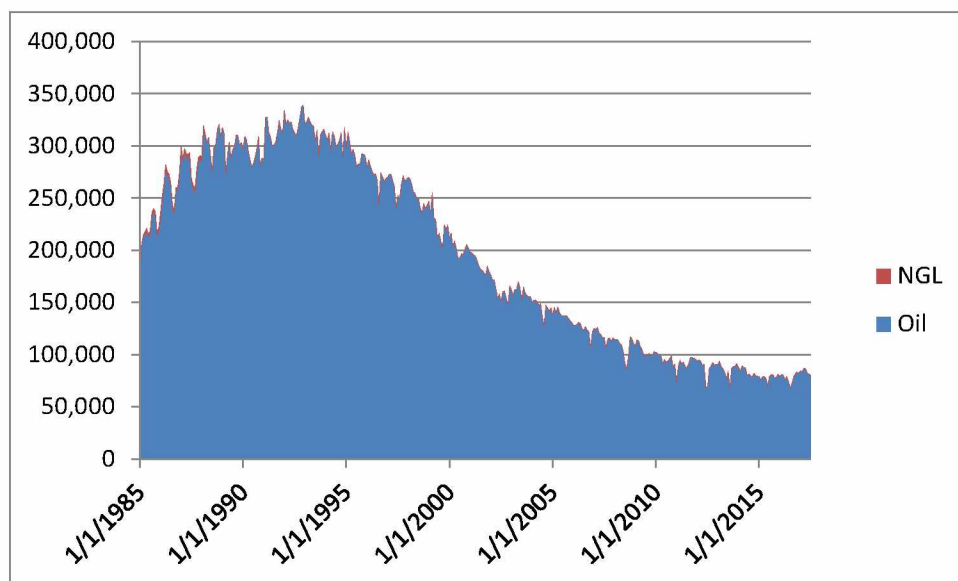


FIGURE 303: KUPARUK OIL AND NGL PRODUCTION

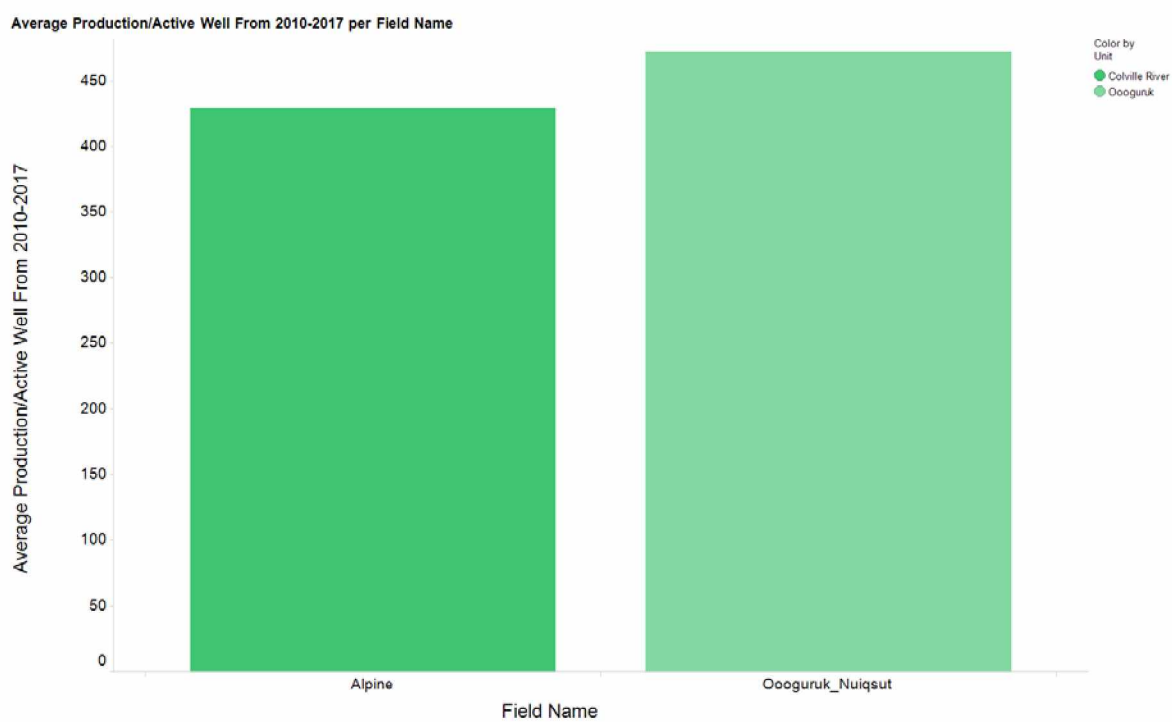


FIGURE 304: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FIELDS WITH ALPINE LIKE FORMATION

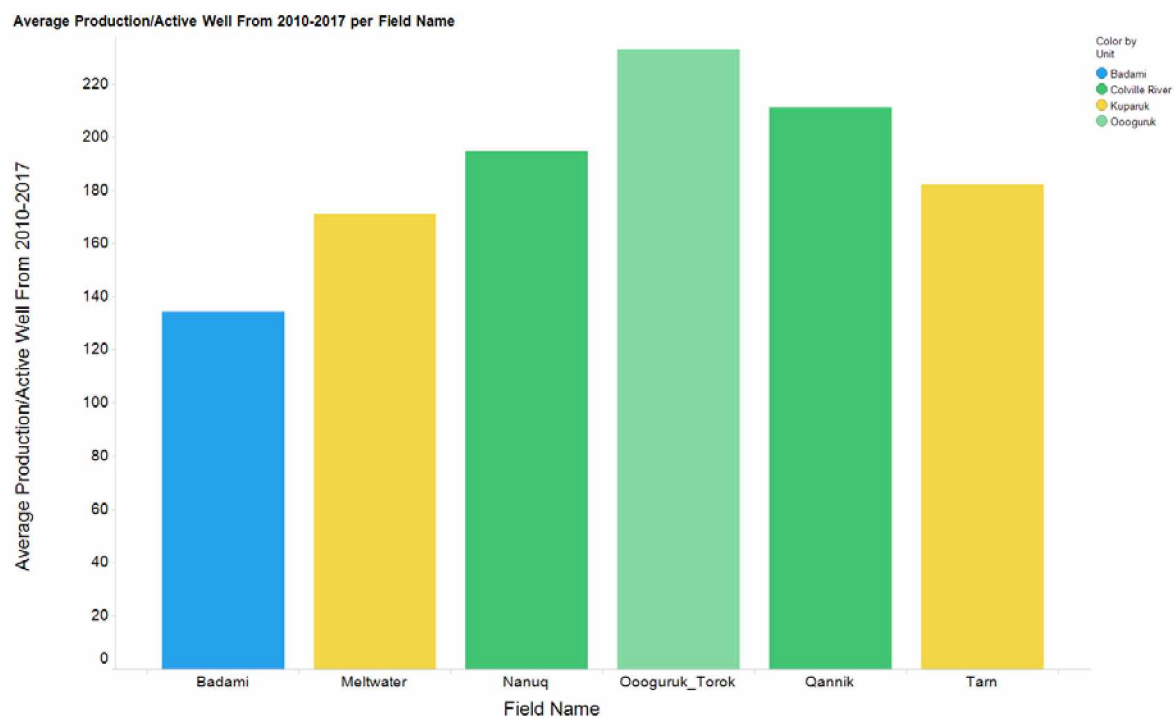


FIGURE 305: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/Well) 2010-2017 FIELDS WITH BROOKIAN FORMATION

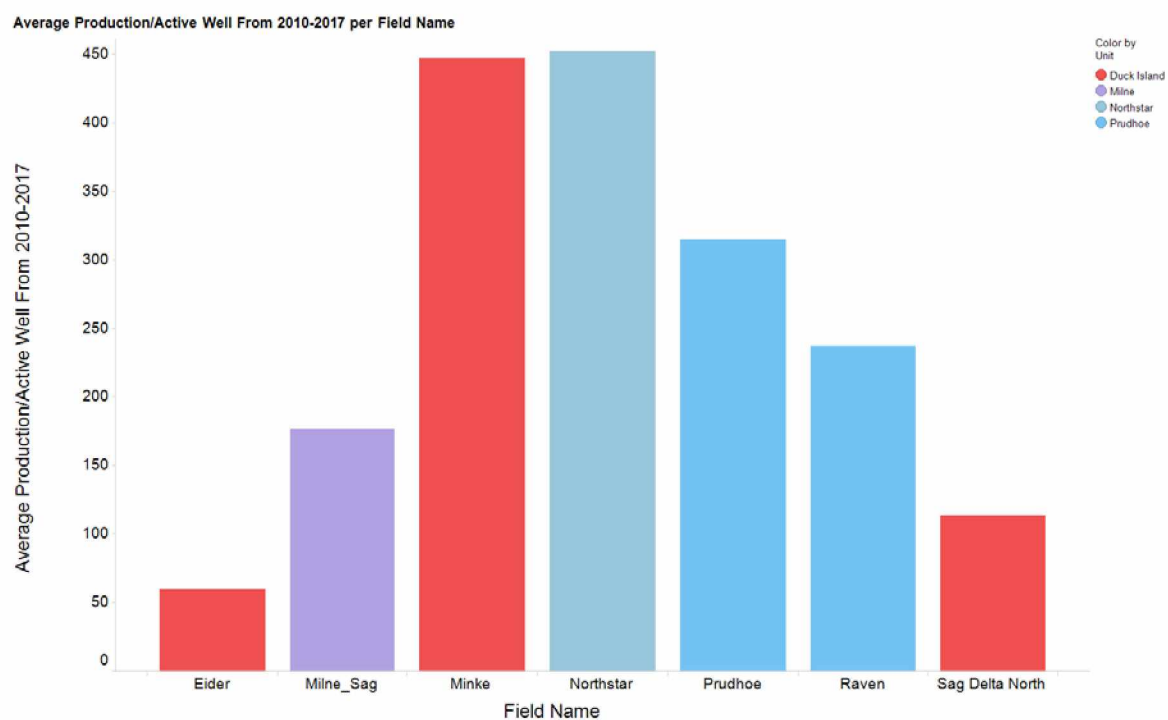


FIGURE 306: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/Well) 2010-2017 FIELDS WITH IVISHAK/SAG FORMATION

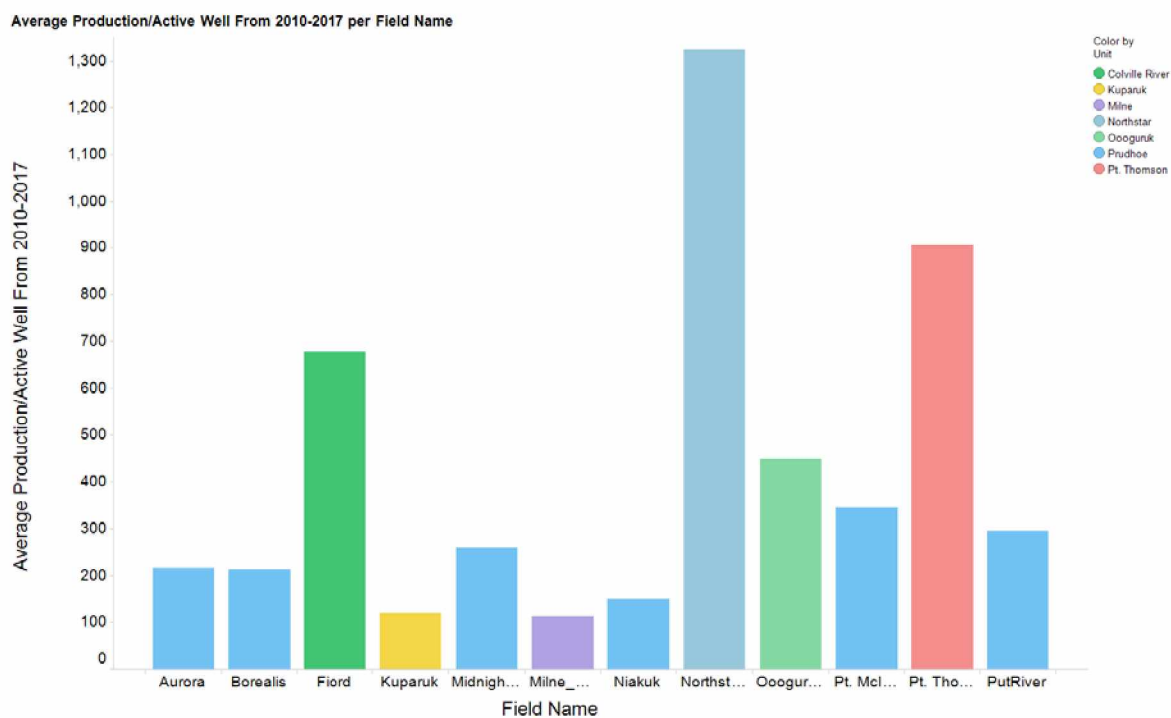


FIGURE 307: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FIELDS WITH KUPARUK LIKE FORMATION

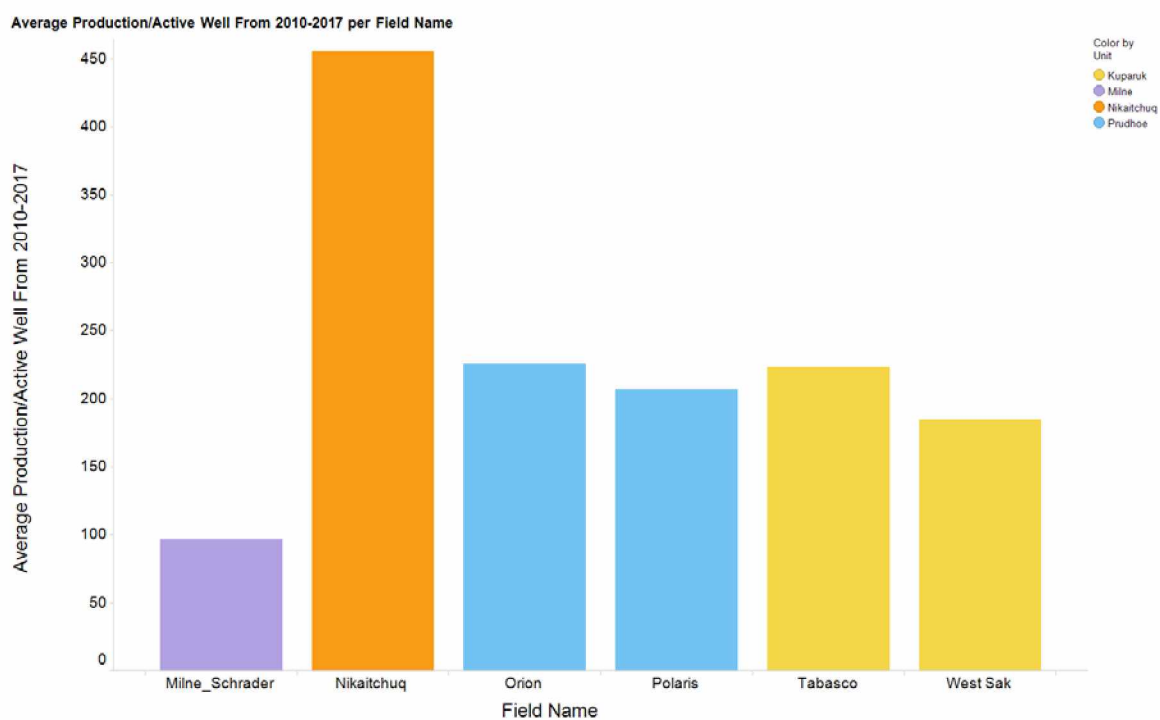


FIGURE 308: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FIELDS WITH SCHRADER BLUFF LIKE FORMATION

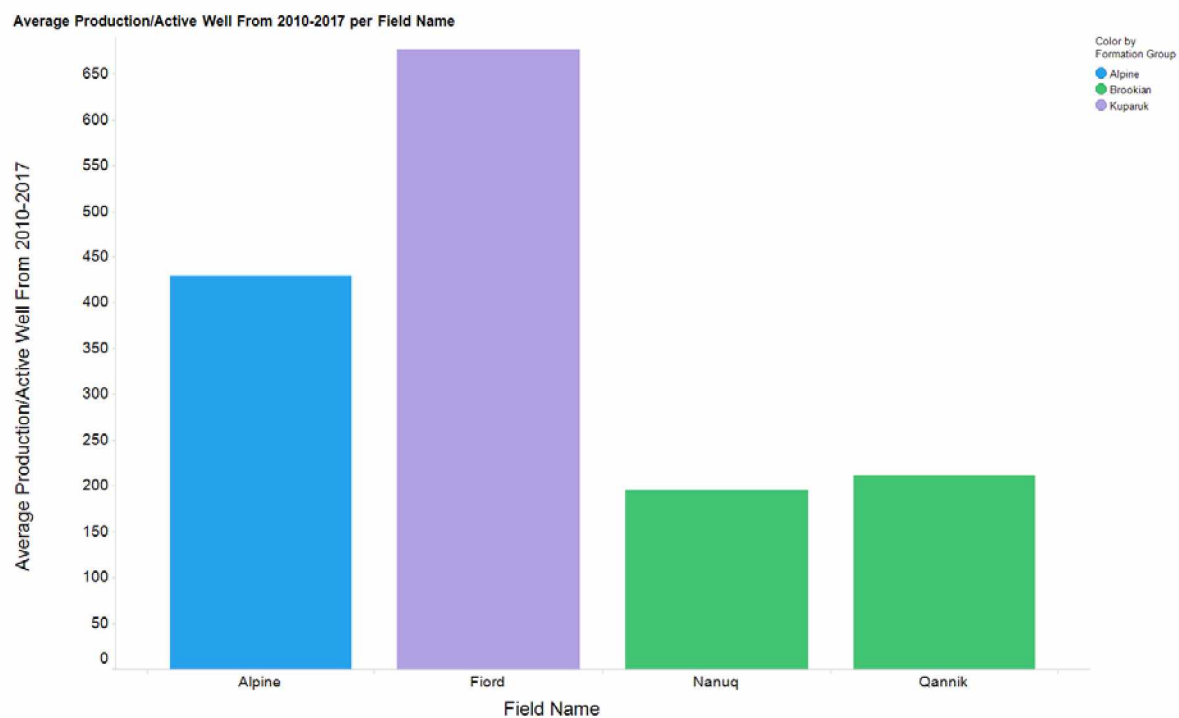


FIGURE 309: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR COLVILLE RIVER UNIT FIELDS

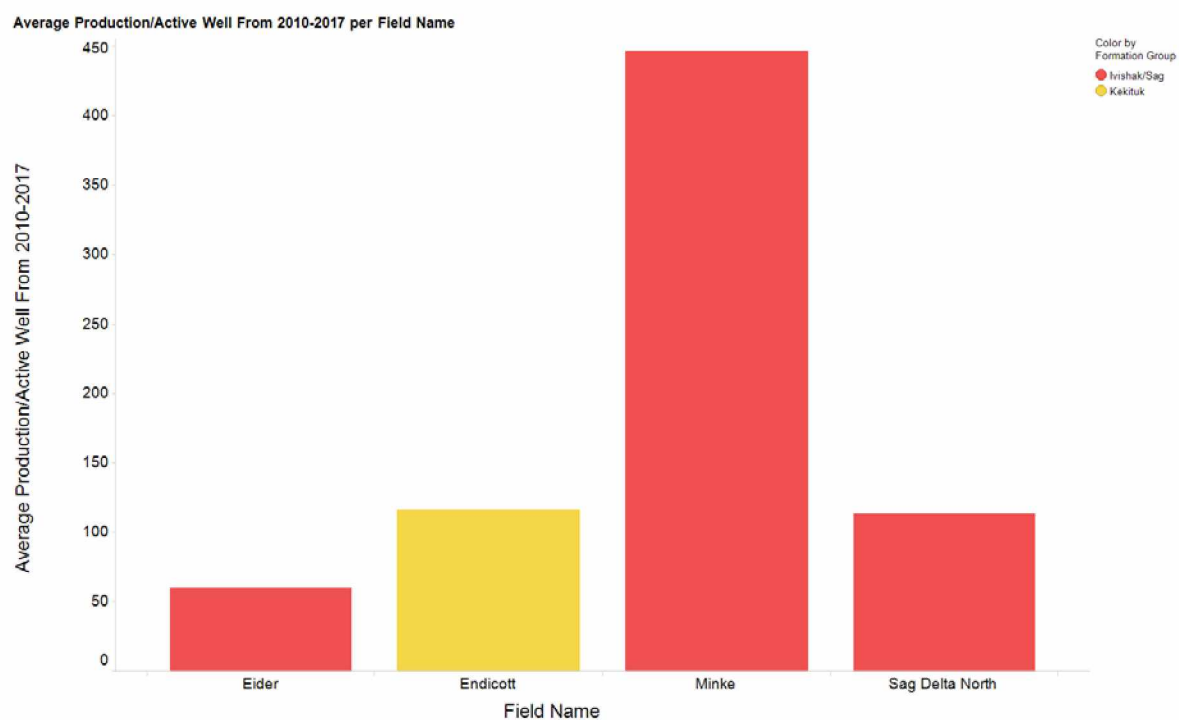


FIGURE 310: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR DUCK ISLAND UNIT FIELDS

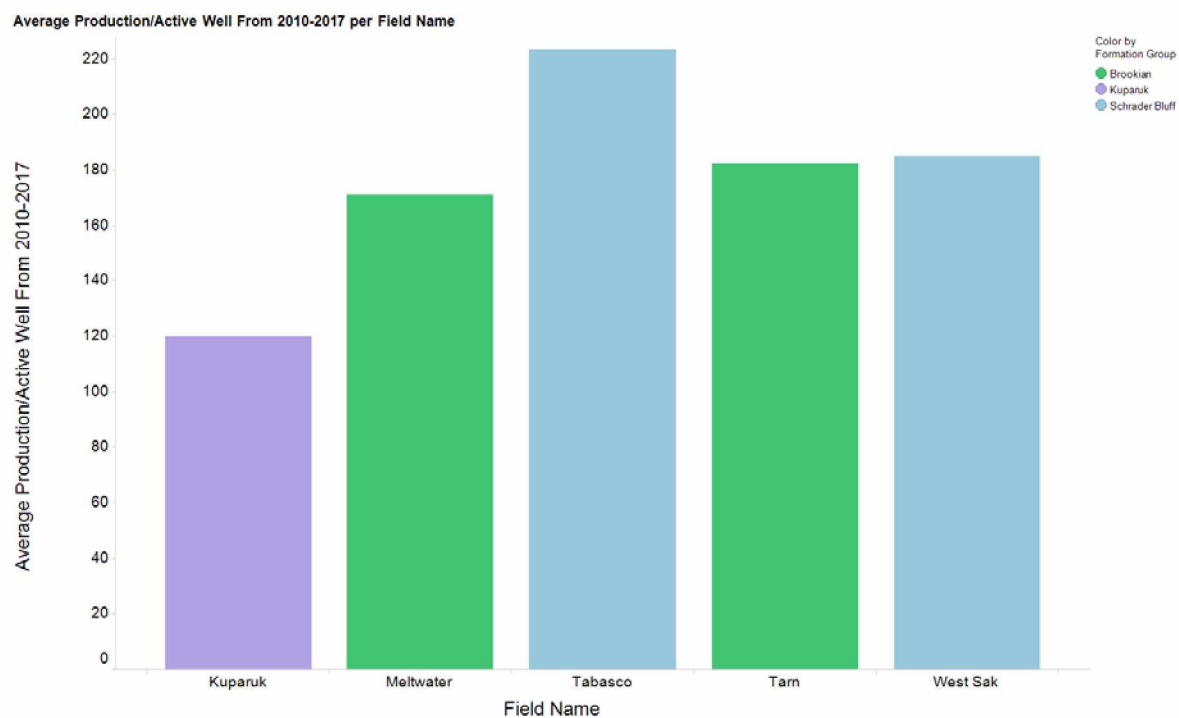


FIGURE 311: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR KUPAŘUK RIVER UNIT FIELDS

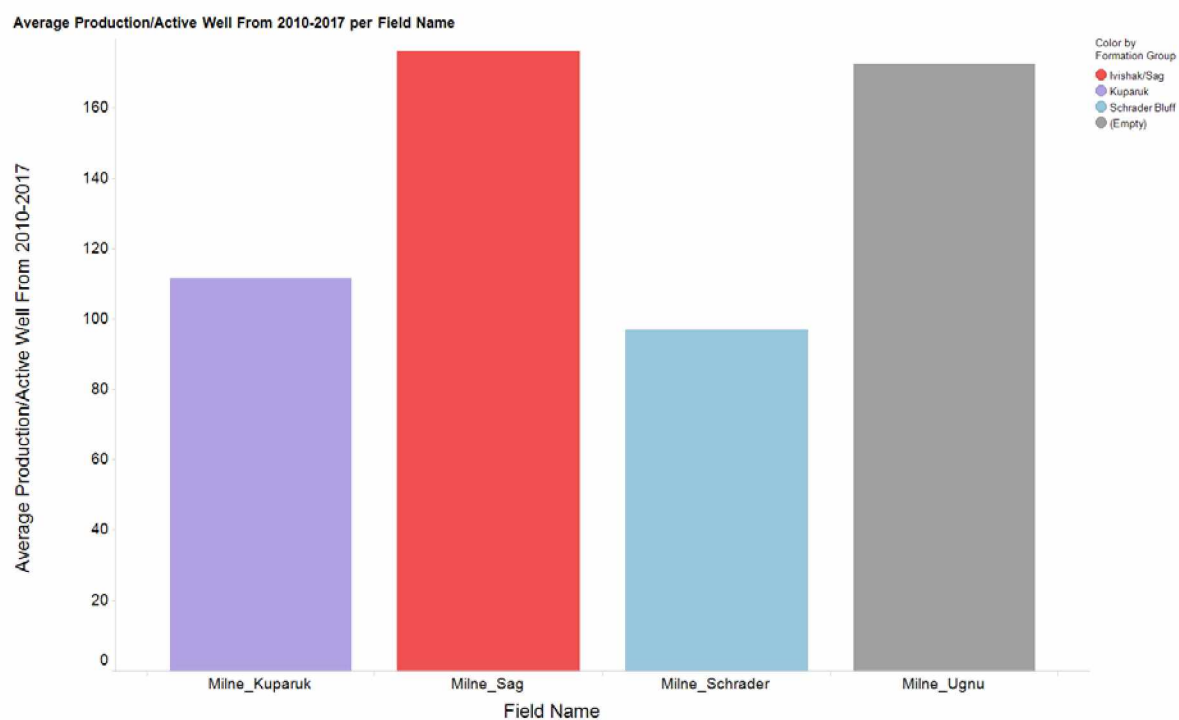


FIGURE 312: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR MILNE POINT UNIT FIELDS

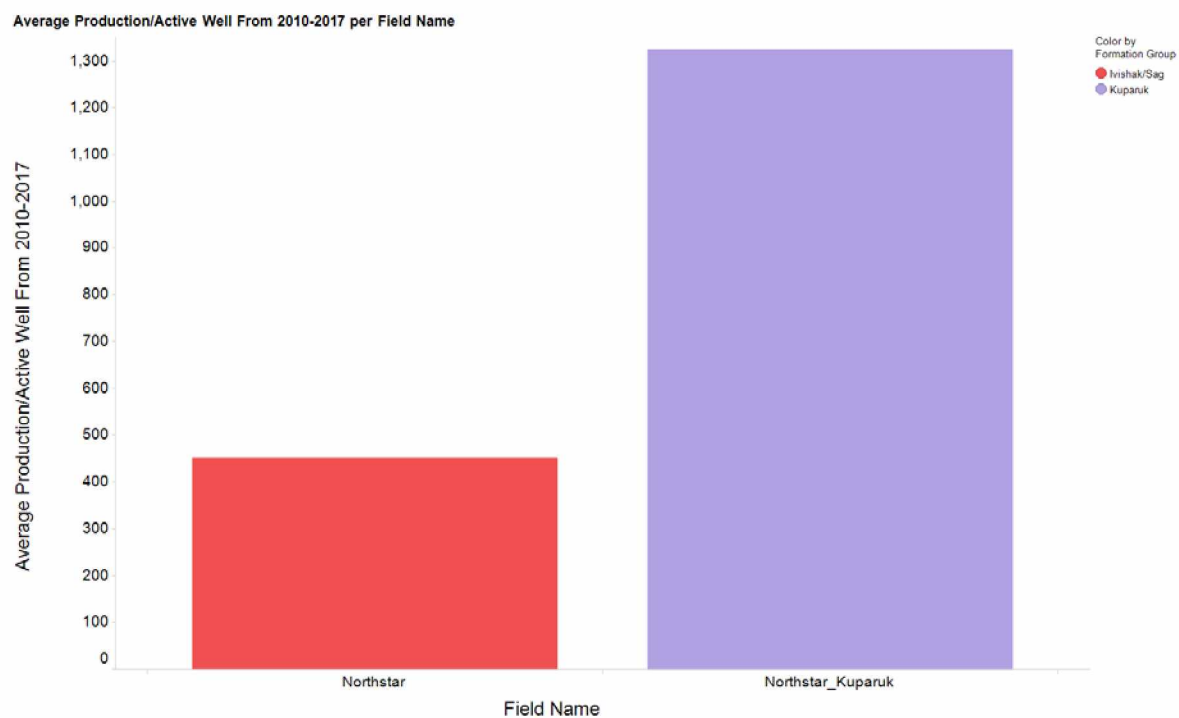


FIGURE 313: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR NORTHSTAR UNIT FIELDS

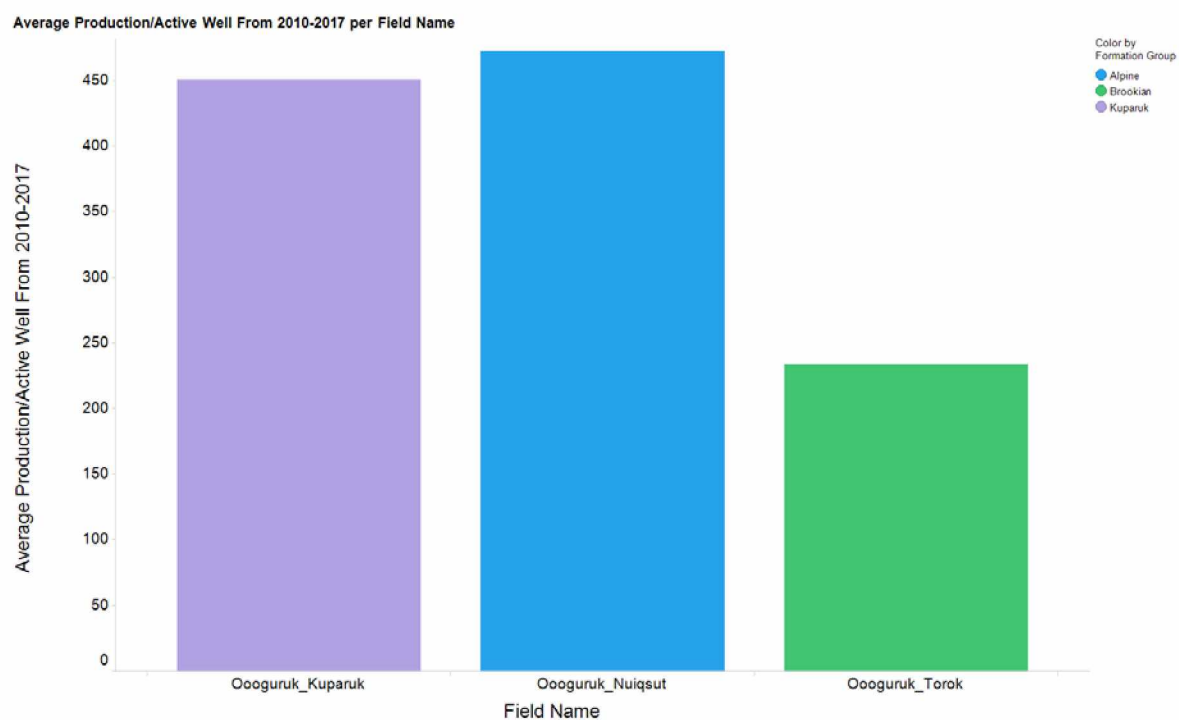


FIGURE 314: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR OOOGURUK UNIT FIELDS



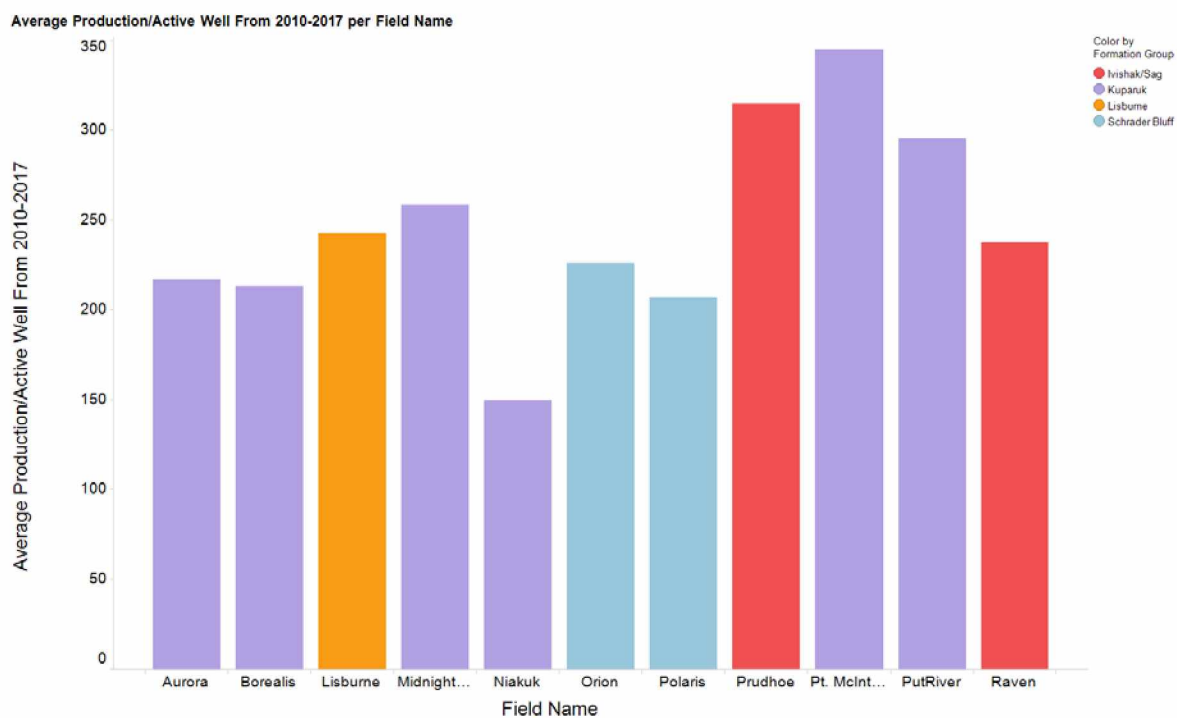


FIGURE 315: AVERAGE PRODUCTION/ACTIVE WELL (BOPD/WELL) 2010-2017 FOR PRUDHOE BAY UNIT FIELDS

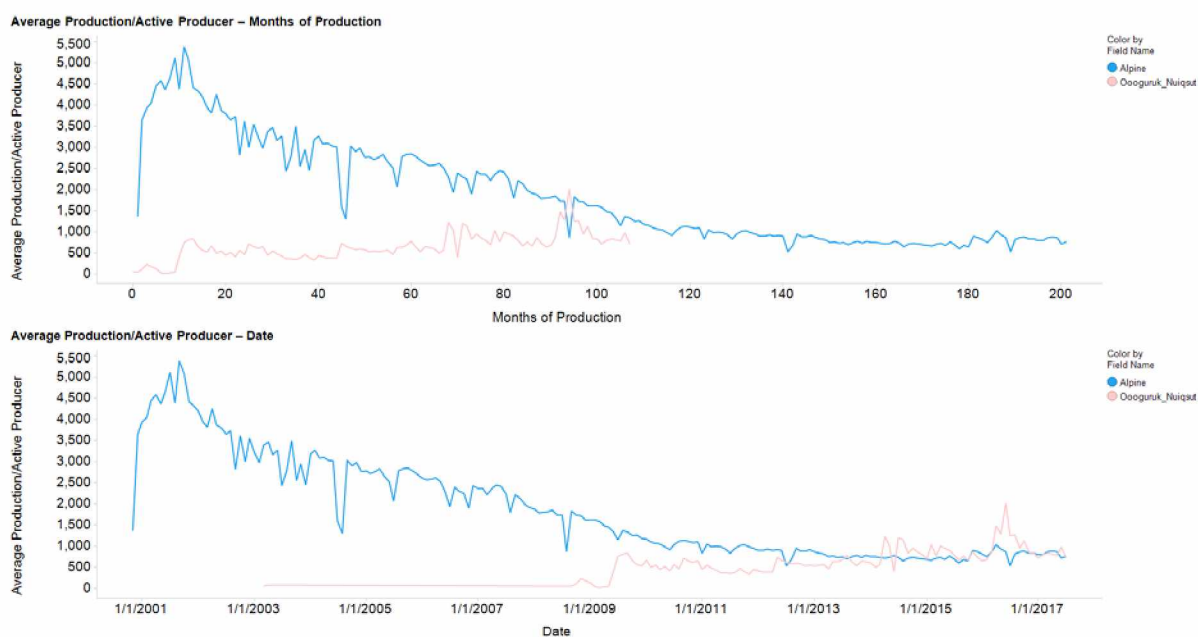


FIGURE 316: AVERAGE PRODUCTION/ACTIVE PRODUCER (BOPD/WELL) FIELDS WITH ALPINE LIKE FORMATION

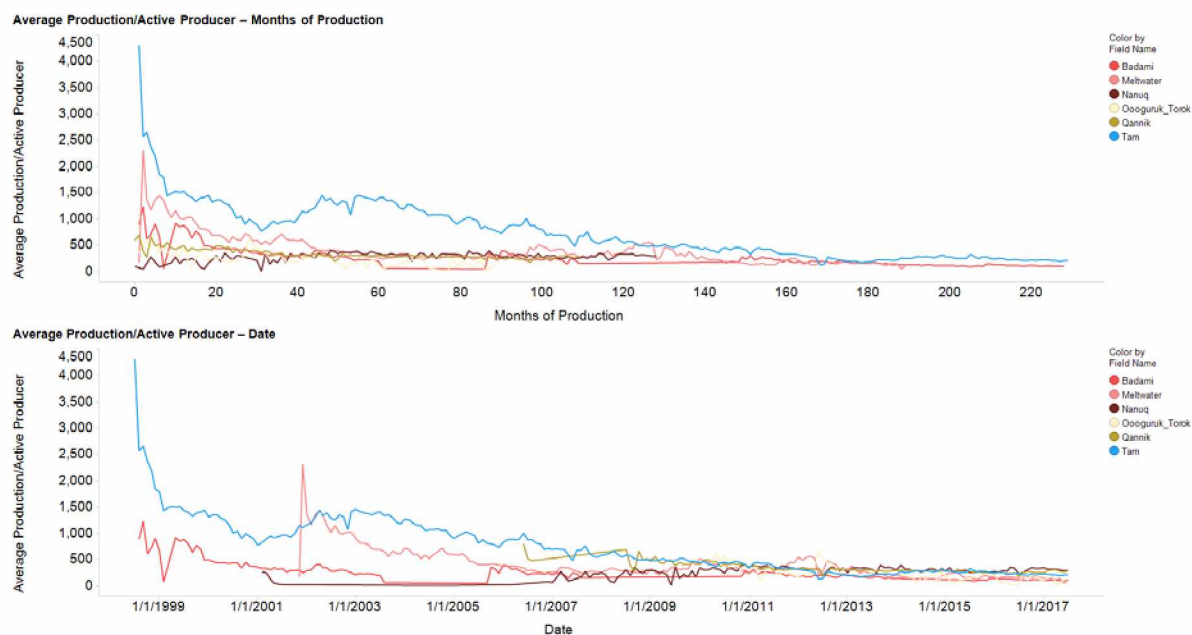


FIGURE 317: AVERAGE PRODUCTION/ACTIVE PRODUCER (BOPD/WELL) FIELDS WITH BROOKIAN FORMATION

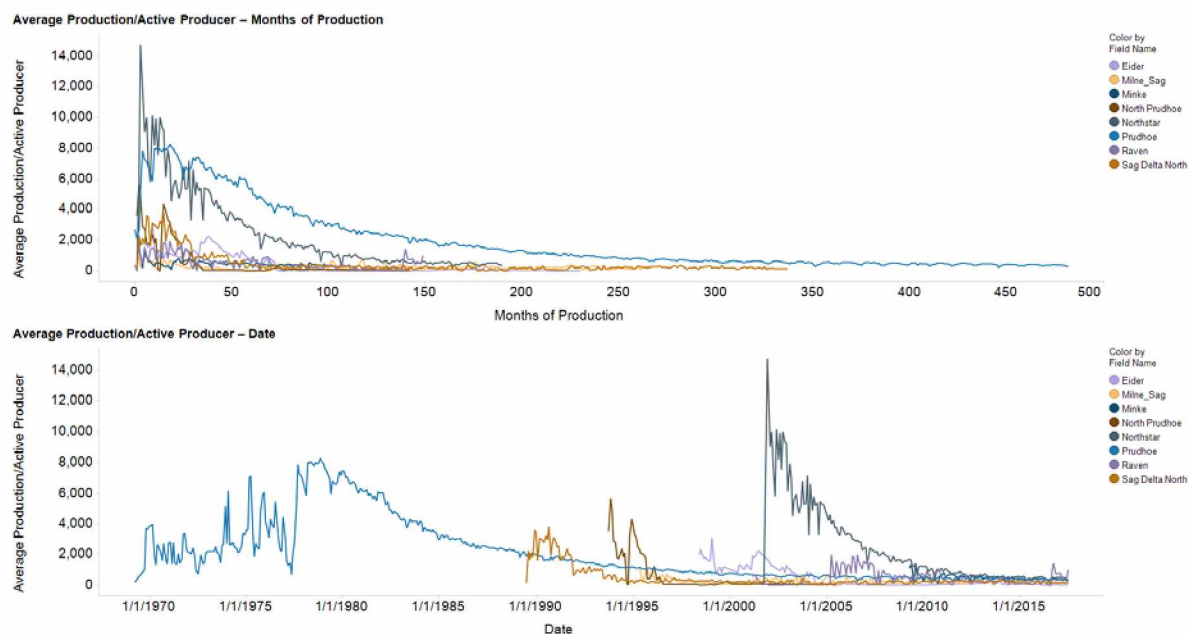


FIGURE 318: AVERAGE PRODUCTION/ACTIVE PRODUCER (BOPD/WELL) FIELDS WITH IVISHAK/SAG FORMATION

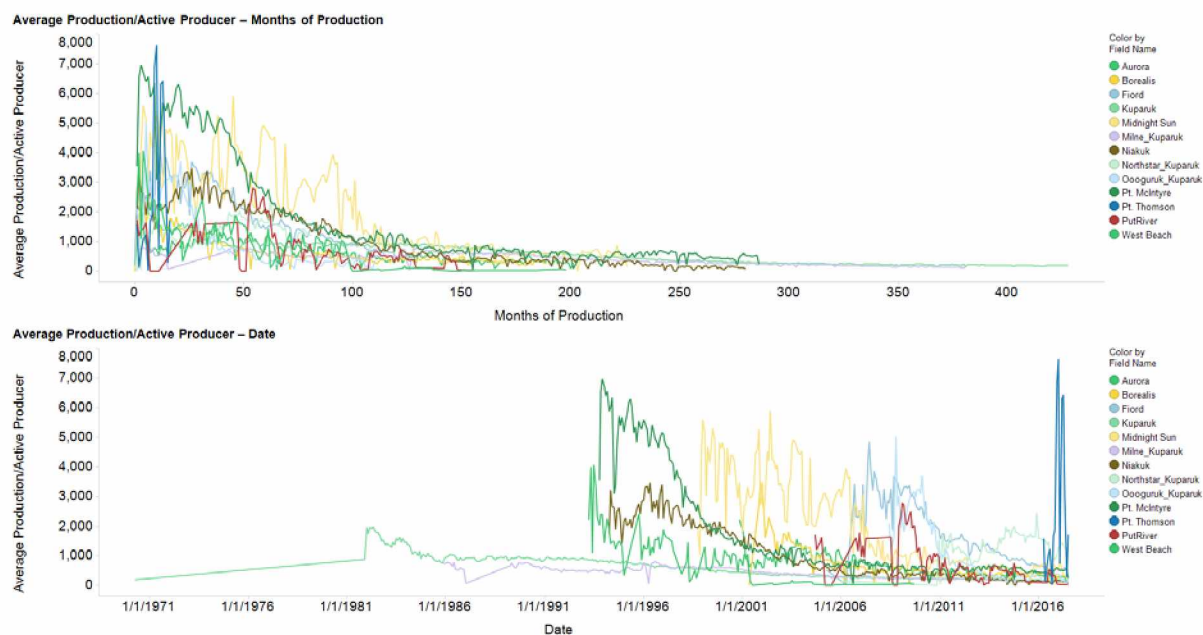


FIGURE 319: AVERAGE PRODUCTION/ACTIVE PRODUCER (BOPD/WELL) FIELDS KUPARUK LIKE FORMATION

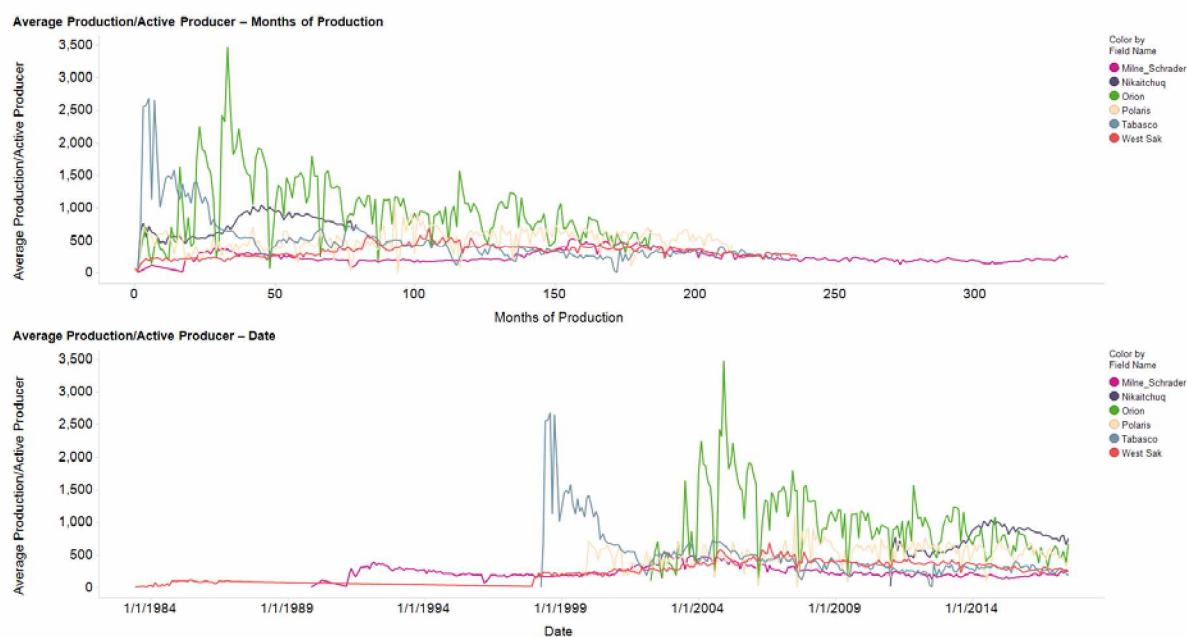


FIGURE 320: AVERAGE PRODUCTION/ACTIVE PRODUCER (BOPD/WELL) FIELDS WITH SCHRADER BLUFF LIKE FORMATION

Original GOR (SCF/STB) vs. Oil Quality Grouping

Oil Quality Grouping

Original GOR (SCF/STB)

Marker by (Shape Number)  
Color by Formation Group

- Alpine
- Brecken
- Kushka/Sag
- Kuparuk
- Lisburne
- Schrader Buff
- (Empty)

Oil Quality Grouping	Formation Group	Label	Original GOR (SCF/STB)
High API	Brecken	Northstar	2150
High API	Brecken	Nannuq	1000
High API	Alpine	Alpine	850
High API	Kuparuk	Nannuq_Kuparuk	780
High API	Kuparuk	Tarn	650
High API	Brecken	Meltwater	600
Light Oil	Brecken	Mine	1850
Light Oil	Brecken	North Prudhoe	950
Light Oil	Brecken	Lisburne	900
Light Oil	Brecken	Elder	850
Light Oil	Brecken	Endicott	800
Light Oil	Brecken	Aurora	750
Light Oil	Brecken	Nainok	700
Light Oil	Brecken	Mine_Sag	900
Light Oil	Brecken	Prudhoe	850
Light Oil	Brecken	Sag Delta North	800
Light Oil	Brecken	Midnight Sun	750
Light Oil	Brecken	Prudhoe	800
Light Oil	Brecken	Prudhoe	850
Light Oil	Brecken	Prudhoe	900
Light Oil	Brecken	Prudhoe	950
Light Oil	Brecken	Prudhoe	1000
Light Oil	Brecken	Prudhoe	1050
Light Oil	Brecken	Prudhoe	1100
Light Oil	Brecken	Prudhoe	1150
Light Oil	Brecken	Prudhoe	1200
Light Oil	Brecken	Prudhoe	1250
Light Oil	Brecken	Prudhoe	1300
Light Oil	Brecken	Prudhoe	1350
Light Oil	Brecken	Prudhoe	1400
Light Oil	Brecken	Prudhoe	1450
Light Oil	Brecken	Prudhoe	1500
Light Oil	Brecken	Prudhoe	1550
Light Oil	Brecken	Prudhoe	1600
Light Oil	Brecken	Prudhoe	1650
Light Oil	Brecken	Prudhoe	1700
Light Oil	Brecken	Prudhoe	1750
Light Oil	Brecken	Prudhoe	1800
Light Oil	Brecken	Prudhoe	1850
Light Oil	Brecken	Prudhoe	1900
Light Oil	Brecken	Prudhoe	1950
Light Oil	Brecken	Prudhoe	2000
Light Oil	Brecken	Prudhoe	2050
Light Oil	Brecken	Prudhoe	2100
Light Oil	Brecken	Prudhoe	2150
Light Oil	Brecken	Prudhoe	2200
Light Oil	Brecken	Prudhoe	2250
Light Oil	Brecken	Prudhoe	2300
Light Oil	Brecken	Prudhoe	2350
Light Oil	Brecken	Prudhoe	2400
Light Oil	Brecken	Prudhoe	2450
Light Oil	Brecken	Prudhoe	2500
Light Oil	Brecken	Prudhoe	2550
Light Oil	Brecken	Prudhoe	2600
Light Oil	Brecken	Prudhoe	2650
Light Oil	Brecken	Prudhoe	2700
Light Oil	Brecken	Prudhoe	2750
Light Oil	Brecken	Prudhoe	2800
Light Oil	Brecken	Prudhoe	2850
Light Oil	Brecken	Prudhoe	2900
Light Oil	Brecken	Prudhoe	2950
Light Oil	Brecken	Prudhoe	3000
Light Oil	Brecken	Prudhoe	3050
Light Oil	Brecken	Prudhoe	3100
Light Oil	Brecken	Prudhoe	3150
Light Oil	Brecken	Prudhoe	3200
Light Oil	Brecken	Prudhoe	3250
Light Oil	Brecken	Prudhoe	3300
Light Oil	Brecken	Prudhoe	3350
Light Oil	Brecken	Prudhoe	3400
Light Oil	Brecken	Prudhoe	3450
Light Oil	Brecken	Prudhoe	3500
Light Oil	Brecken	Prudhoe	3550
Light Oil	Brecken	Prudhoe	3600
Light Oil	Brecken	Prudhoe	3650
Light Oil	Brecken	Prudhoe	3700
Light Oil	Brecken	Prudhoe	3750
Light Oil	Brecken	Prudhoe	3800
Light Oil	Brecken	Prudhoe	3850
Light Oil	Brecken	Prudhoe	3900
Light Oil	Brecken	Prudhoe	3950
Light Oil	Brecken	Prudhoe	4000
Light Oil	Brecken	Prudhoe	4050
Light Oil	Brecken	Prudhoe	4100
Light Oil	Brecken	Prudhoe	4150
Light Oil	Brecken	Prudhoe	4200
Light Oil	Brecken	Prudhoe	4250
Light Oil	Brecken	Prudhoe	4300
Light Oil	Brecken	Prudhoe	4350
Light Oil	Brecken	Prudhoe	4400
Light Oil	Brecken	Prudhoe	4450
Light Oil	Brecken	Prudhoe	4500

FIGURE 322: ORIGINAL GAS OIL RATIO RANGES GROUPED BY OIL QUALITY

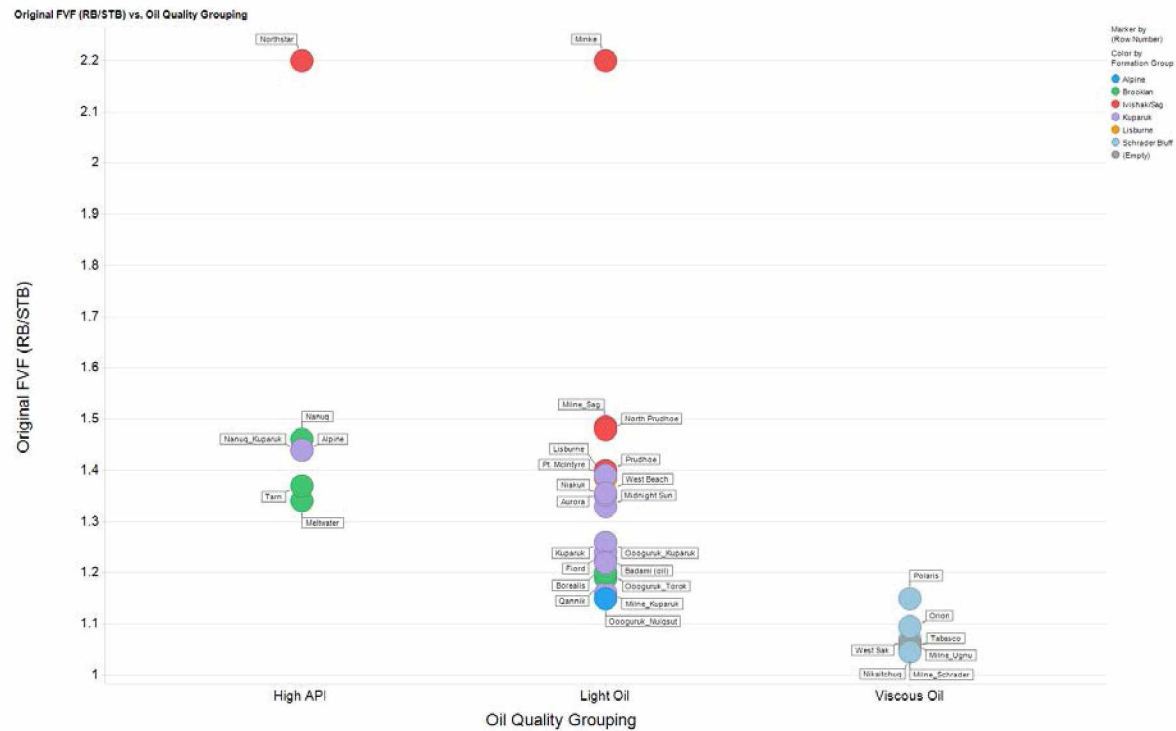


FIGURE 323: ORIGINAL FORMATION VOLUME FACTOR RANGES GROUPED BY OIL QUALITY

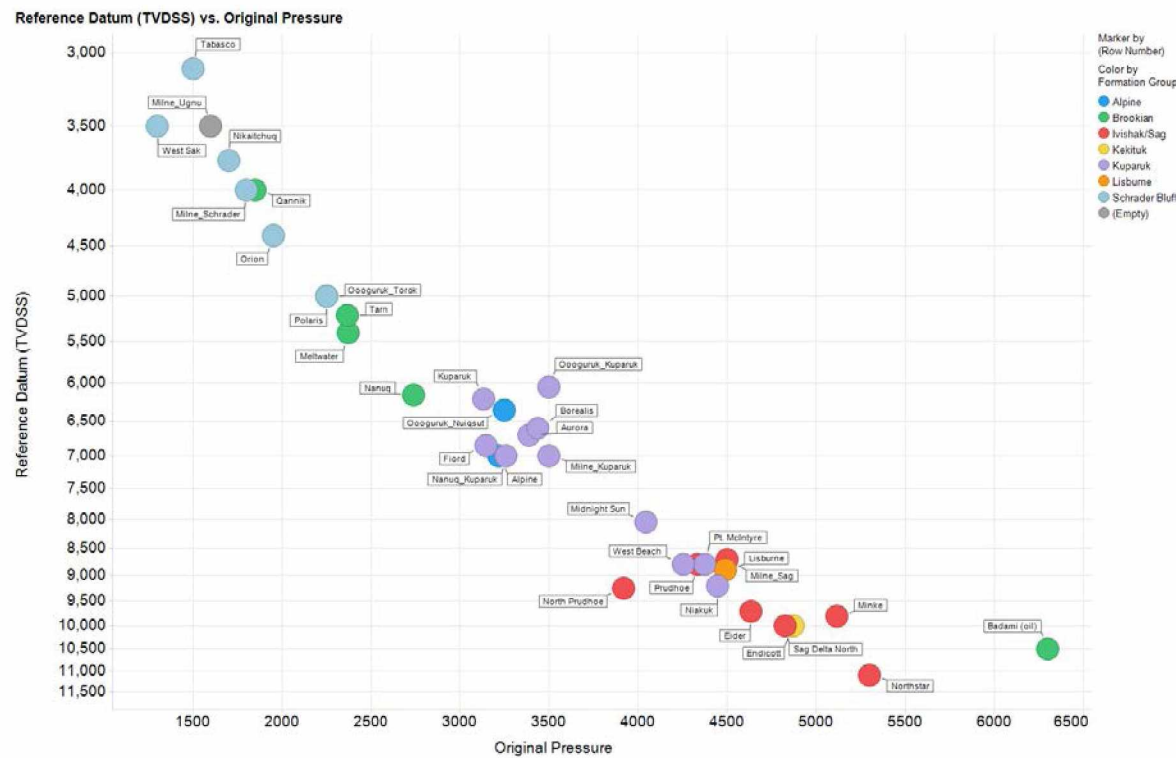


FIGURE 324: REFERENCE DATUM VS. ORIGINAL PRESSURE

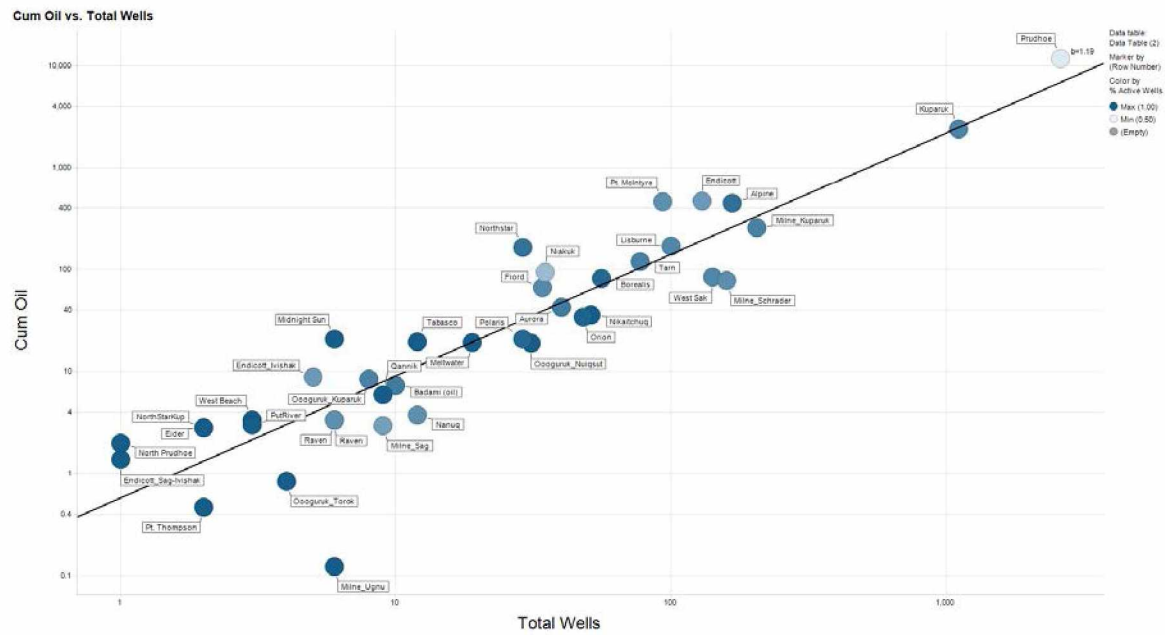


FIGURE 325: CUM OIL VS. TOTAL WELLS BY FIELD

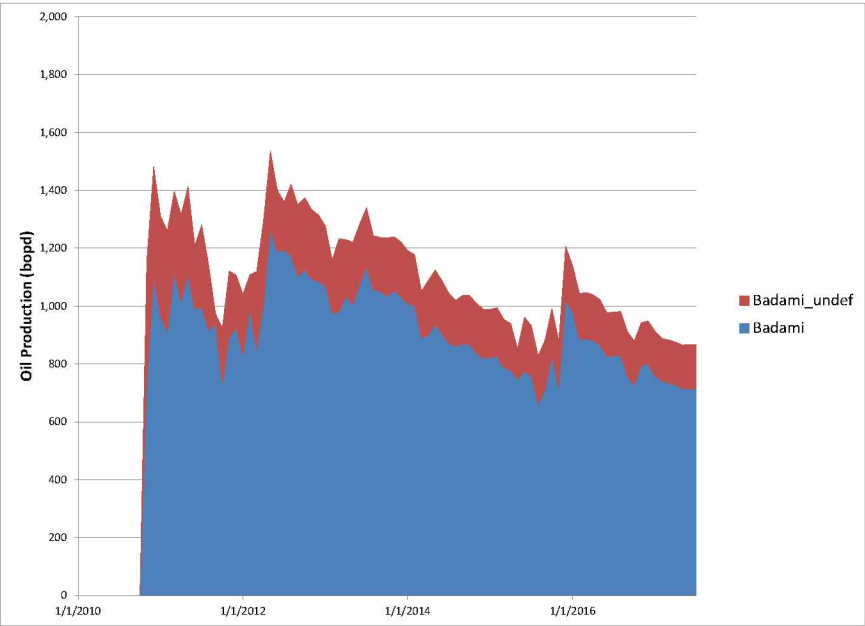


FIGURE 326: RECENT BADAMI UNIT PRODUCTION



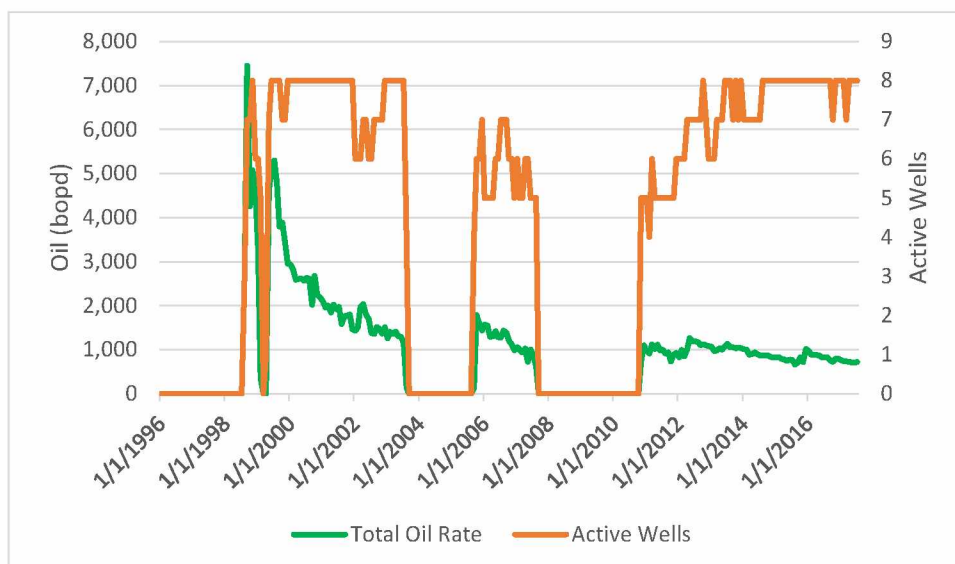


FIGURE 327: BADAMI PRODUCTION AND ACTIVE WELLS

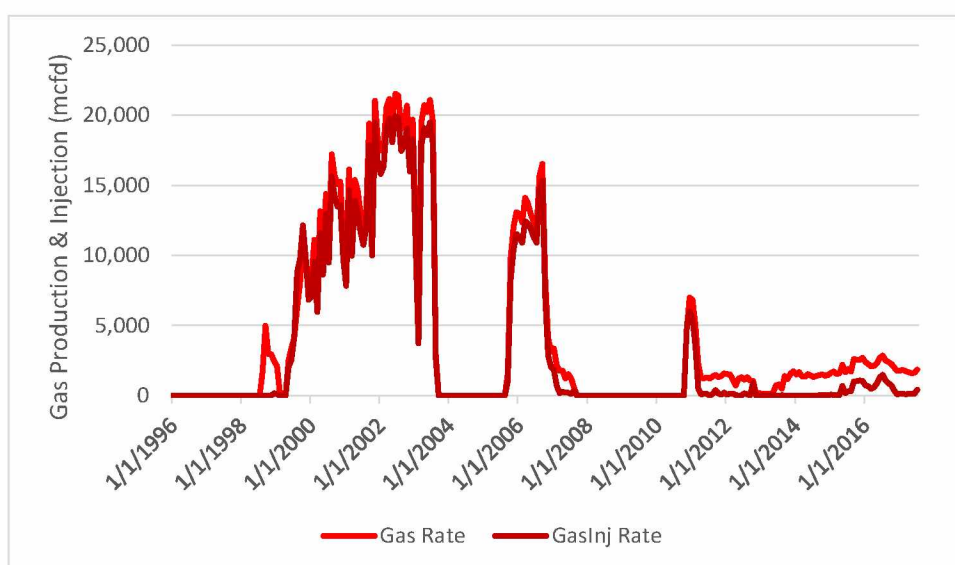


FIGURE 328: BADAMI GAS PRODUCTION AND INJECTION RATES

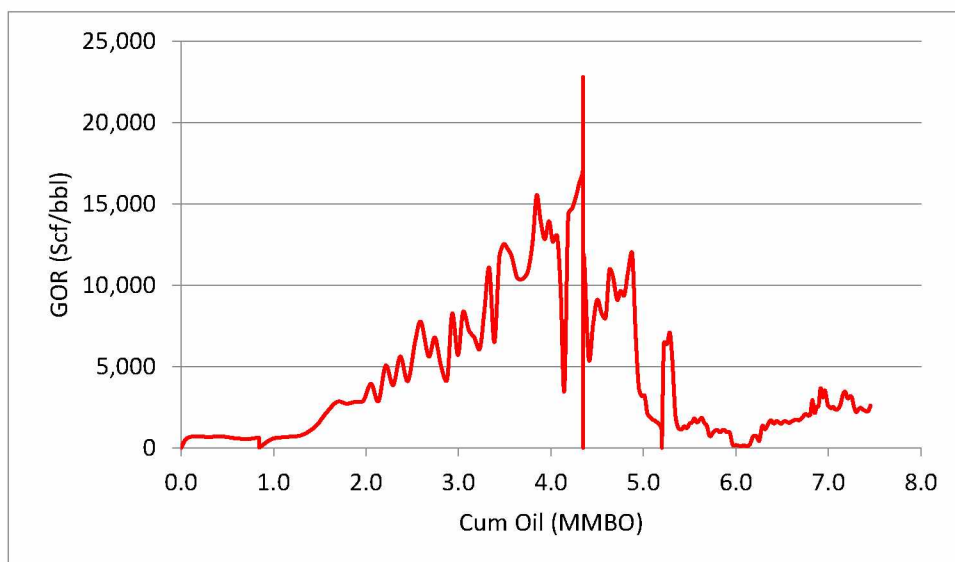


FIGURE 329: BADAMI GAS OIL RATIO VS CUM OIL

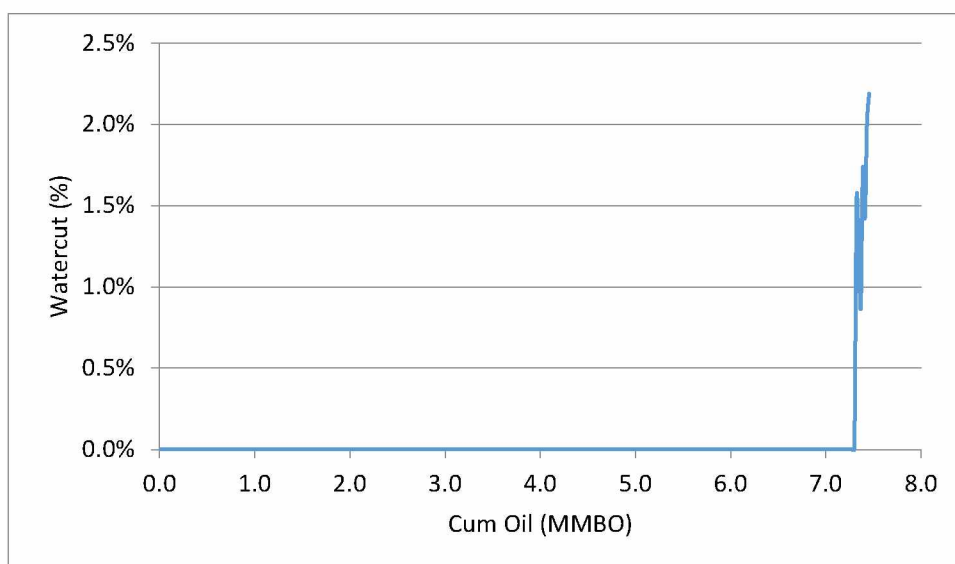


FIGURE 330: BADAMI WATERCUT VS. CUM OIL

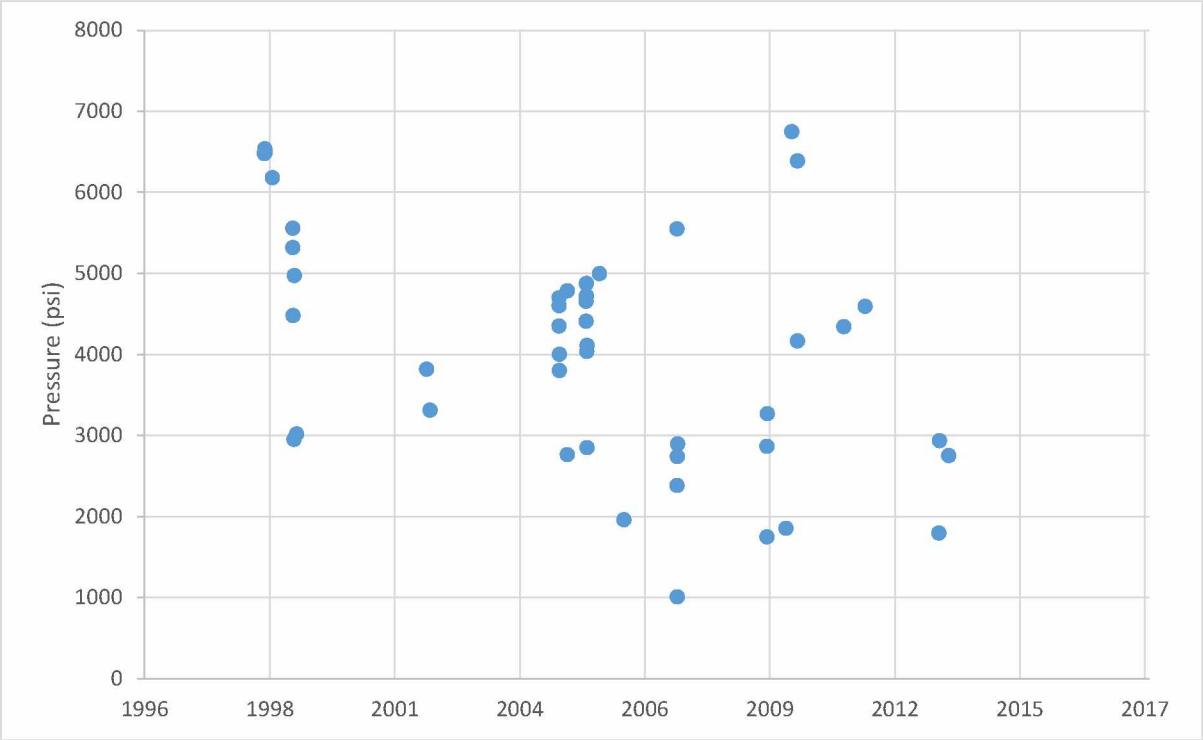


FIGURE 331: BADAMI PRESSURES

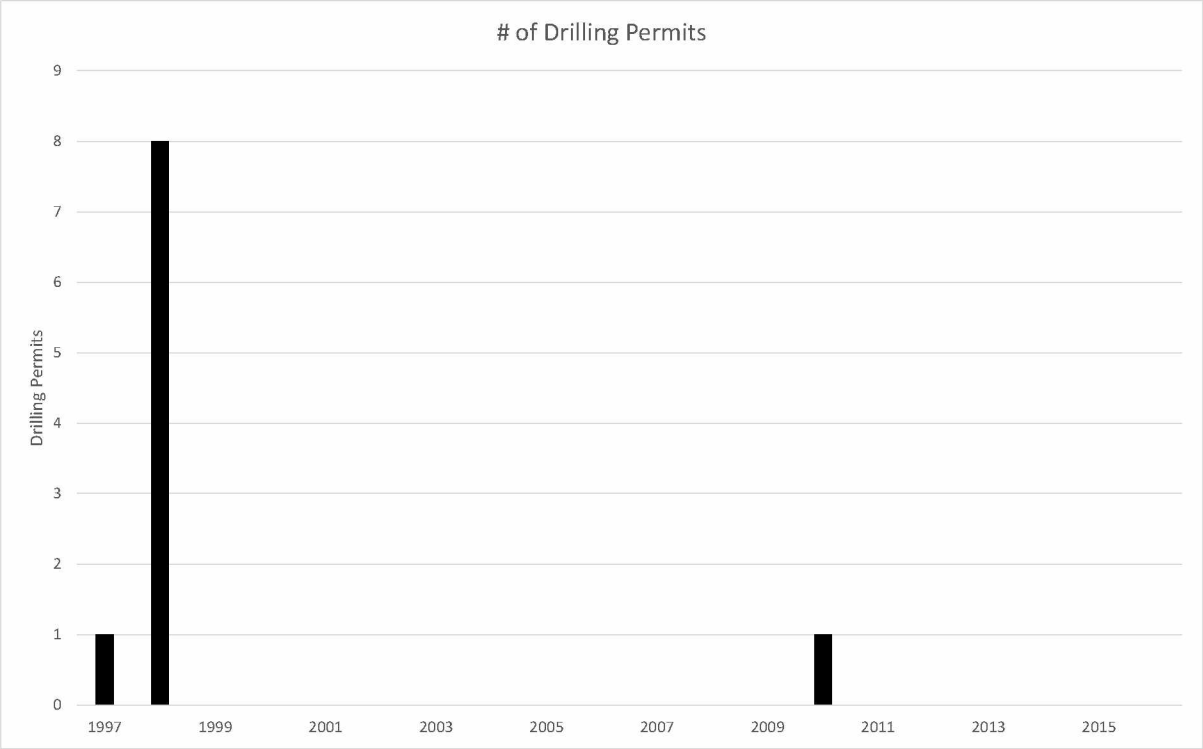


FIGURE 332: BADAMI DRILLING PERMITS BY YEAR

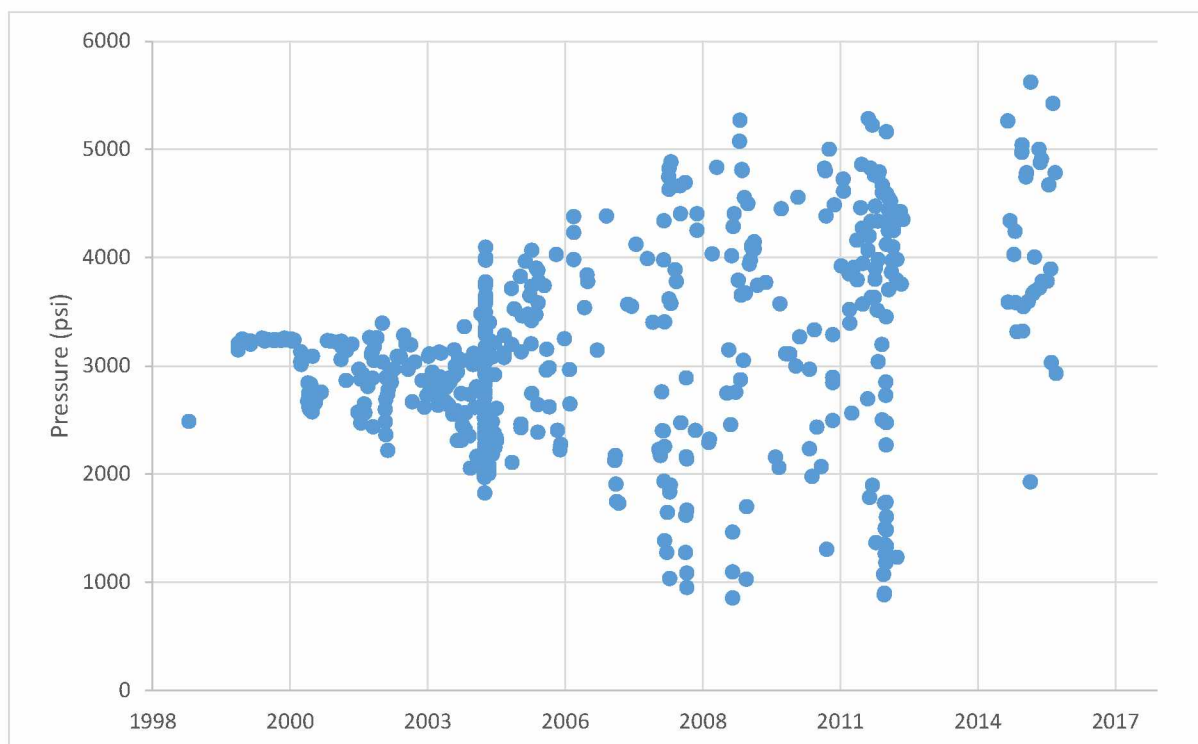


FIGURE 333: ALPINE PRESSURES

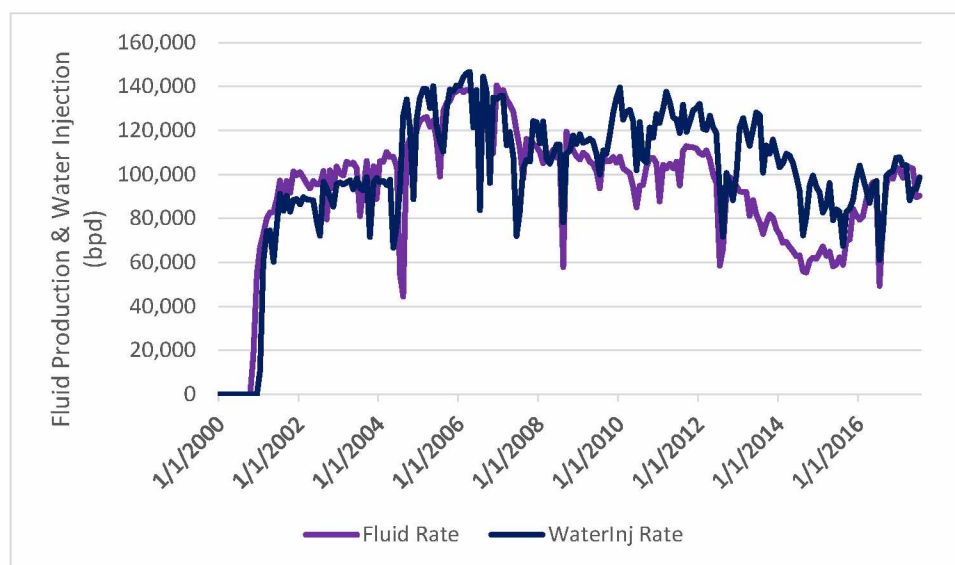


FIGURE 334: ALPINE FLUID PRODUCTION AND WATER INJECTION

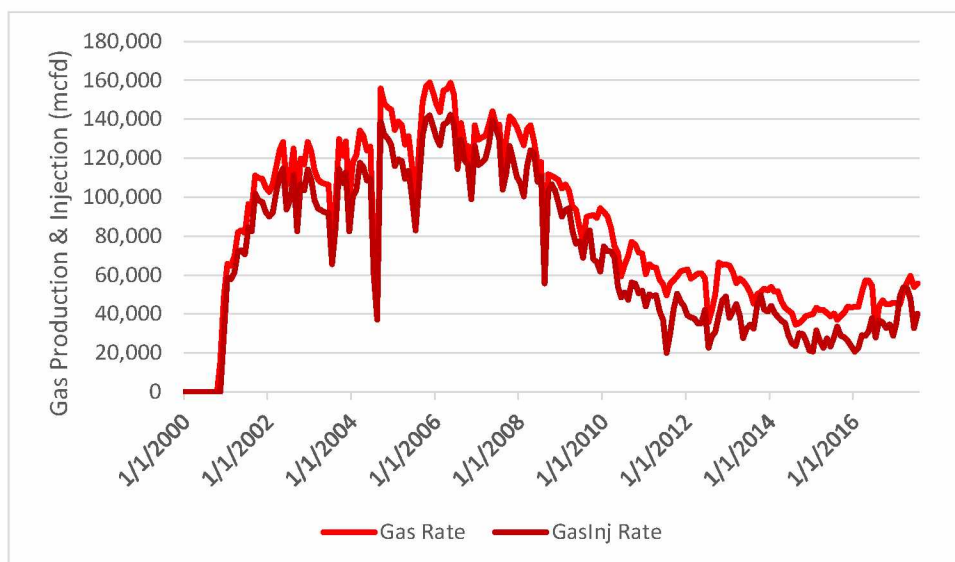


FIGURE 335: ALPINE GAS PRODUCTION AND INJECTION

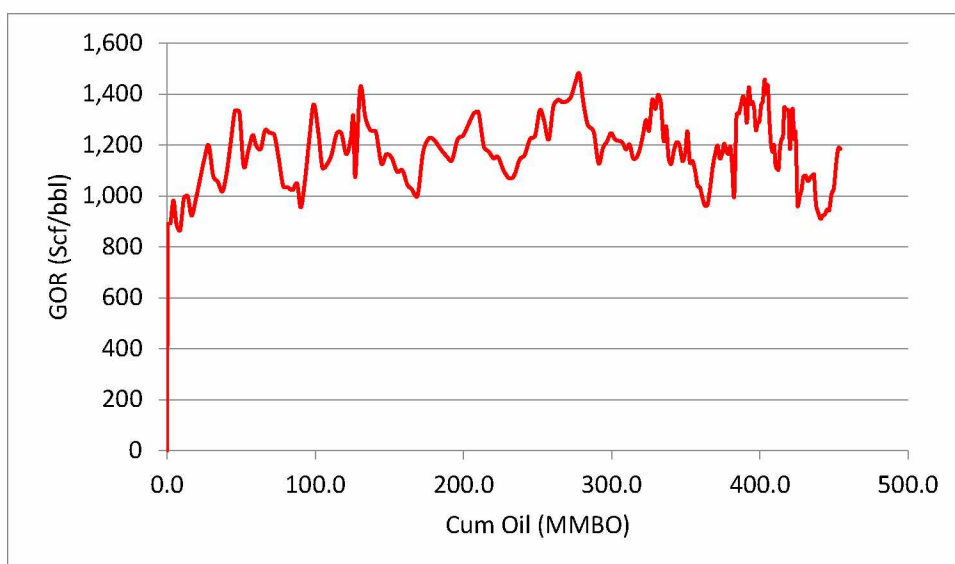


FIGURE 336: ALPINE GAS OIL RATIO VS CUM OIL

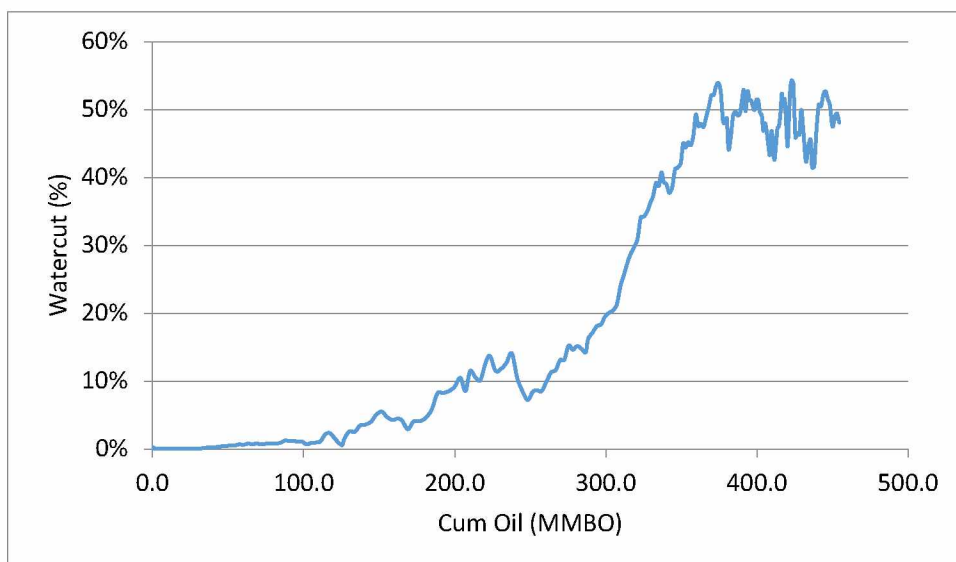


FIGURE 337: ALPINE WATERCUT VS CUM OIL

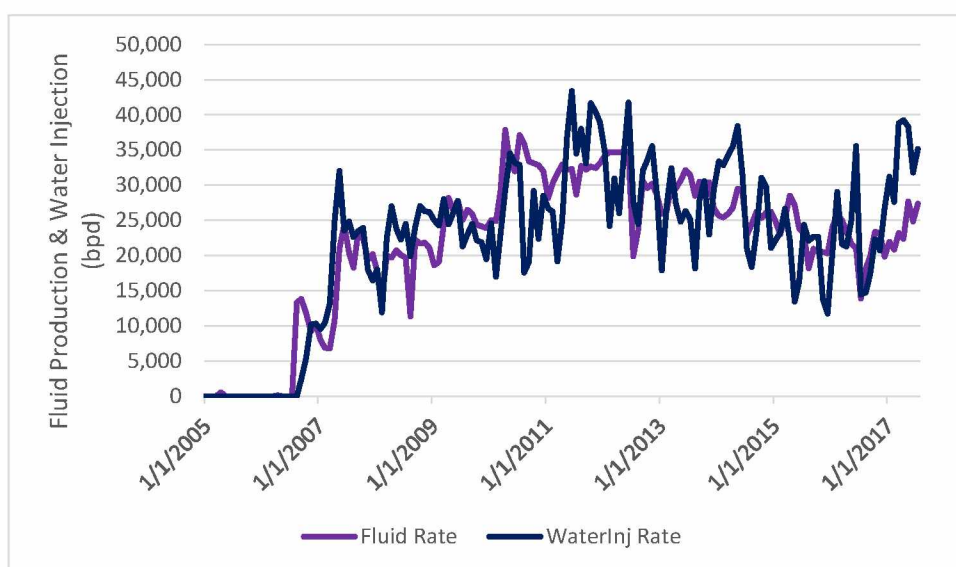


FIGURE 338: FIORD FLUID RATE AND WATER INJECTION



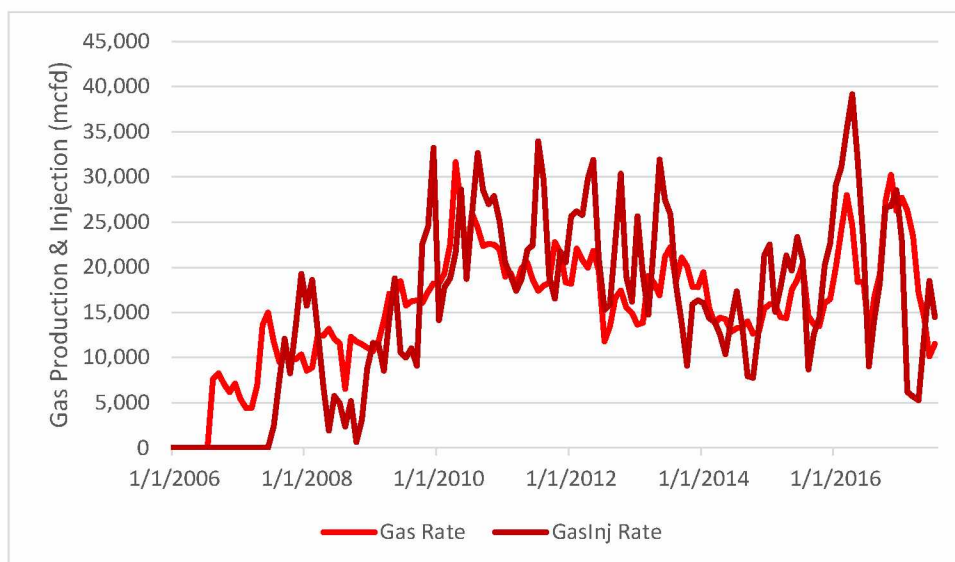


FIGURE 339: FIORD GAS PRODUCTION AND INJECTION

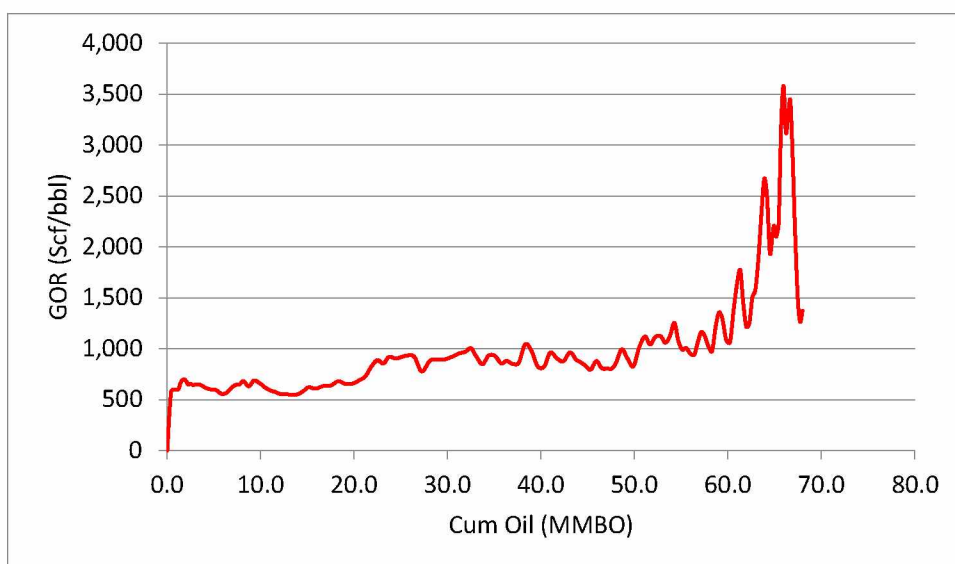


FIGURE 340: FIORD GAS OIL RATIO VS. CUM OIL

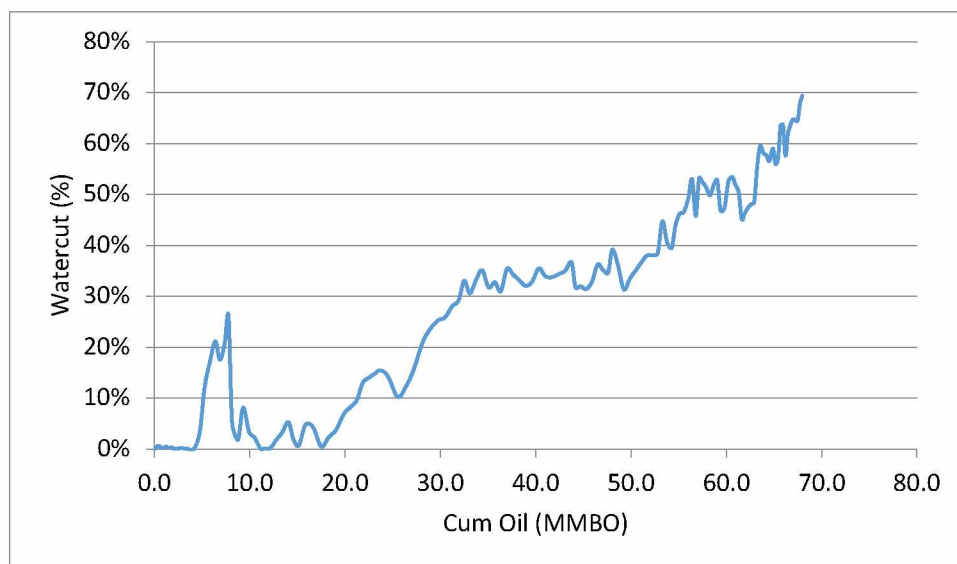


FIGURE 341: FJORD WATERCUT VS. CUM OIL

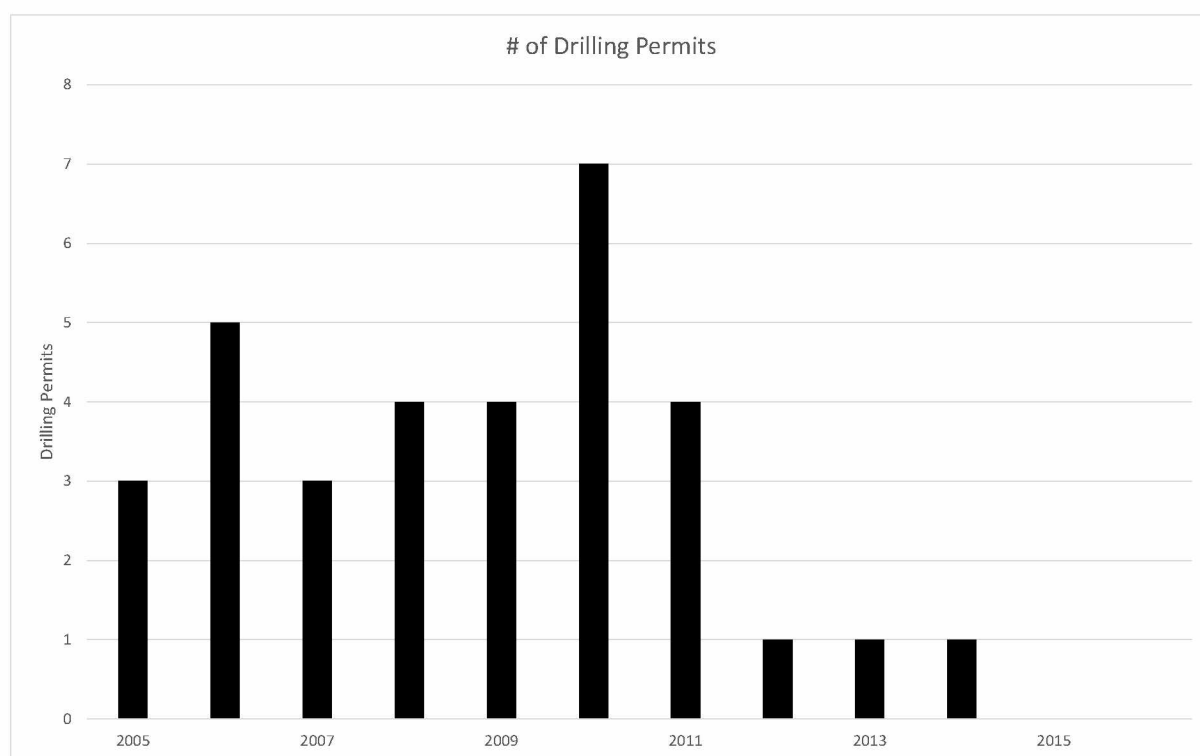


FIGURE 342: FJORD DRILLING PERMITS BY YEAR

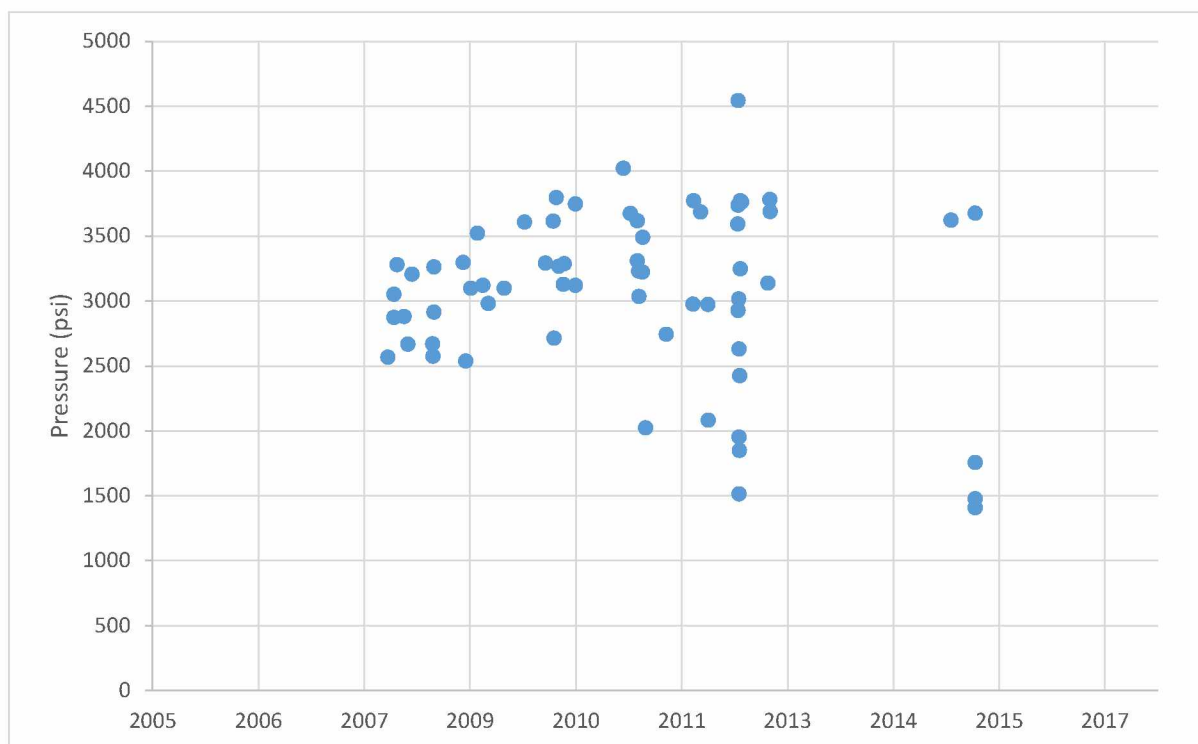


FIGURE 343: FIORD PRESSURES

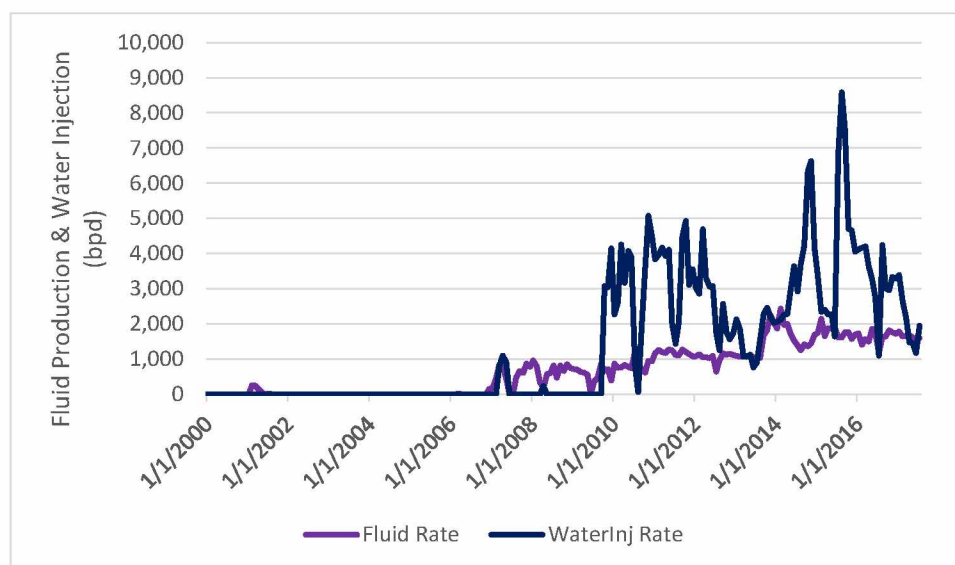


FIGURE 344: NANUQ FLUID RATE AND WATER INJECTION

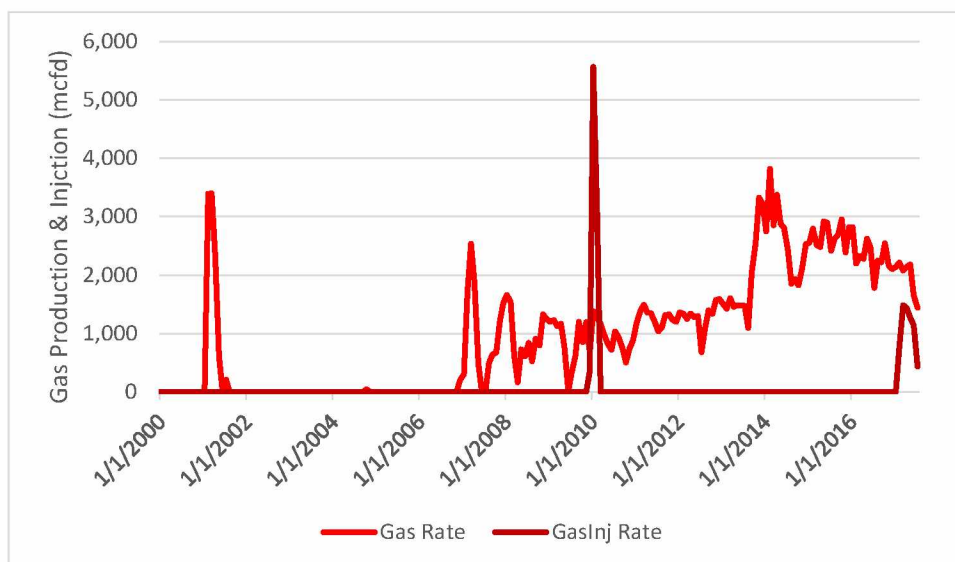


FIGURE 345: NANUQ GAS PRODUCTION &amp; INJECTION

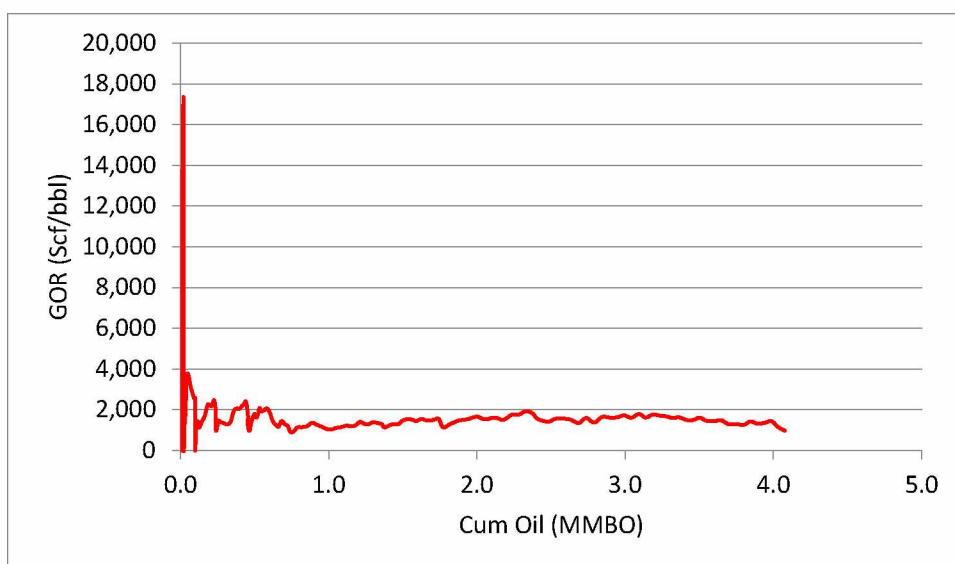


FIGURE 346: NANUQ GAS OIL RATIO VS. CUM OIL

A scatter plot showing the relationship between Year (X-axis) and Pressure (psi) (Y-axis) for the period 2000-2017. The X-axis ranges from 1998 to 2017 with major ticks every 3 years. The Y-axis ranges from 0 to 3500 psi with major ticks every 500 psi. The data points are blue circles. Most data points are clustered between 2006 and 2009, with pressures ranging from approximately 2250 to 3250 psi. There are a few outliers at higher years: one at approximately 2011 with a pressure of 1800 psi, and another at approximately 2014 with a pressure of 2800 psi.

FIGURE 348: NANUQ PRESSURES

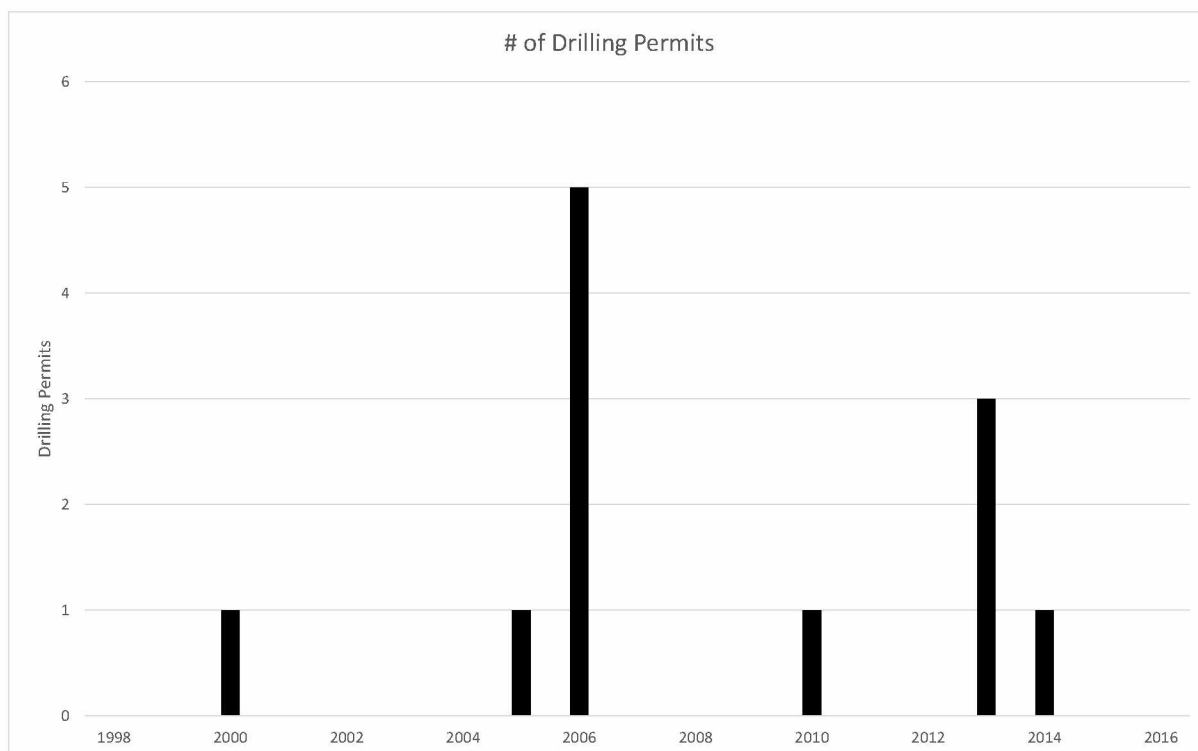


FIGURE 349: NANUQ DRILLING PERMITS BY YEAR

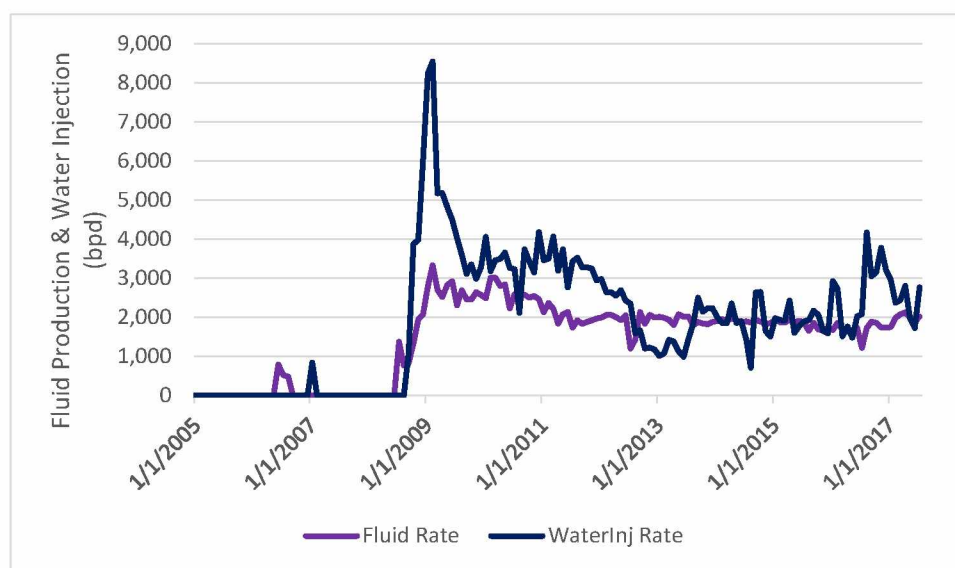


FIGURE 350: QANNIK FLUID PRODUCTION &amp; WATER INJECTION



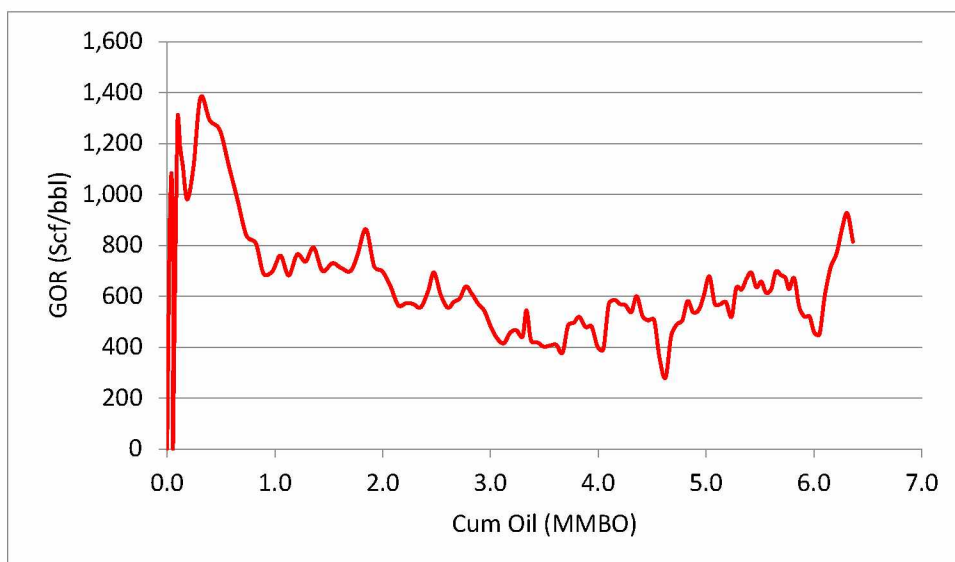


FIGURE 351: QANNIK GAS OIL RATIO VS. CUM OIL

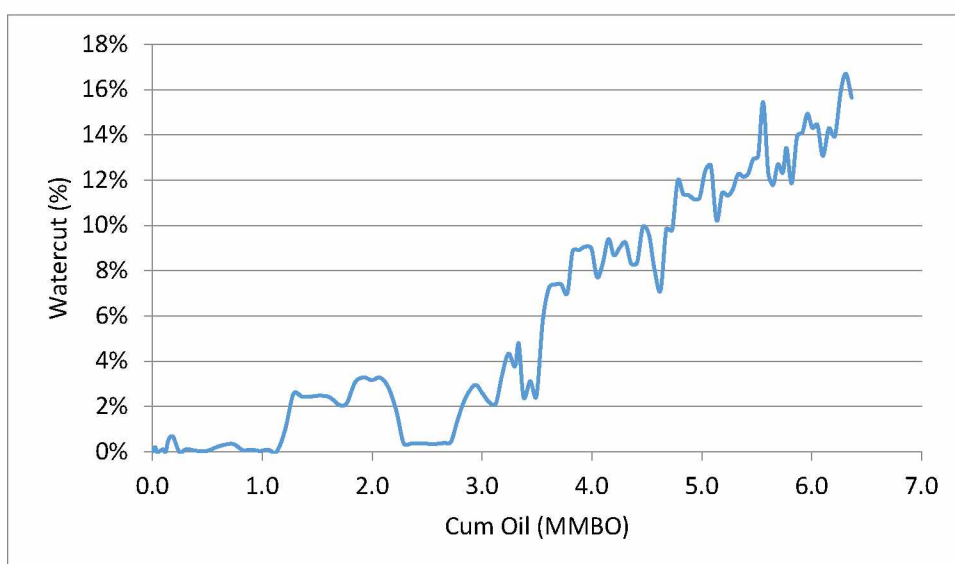


FIGURE 352: QANNIK WATERCUT VS. CUM OIL

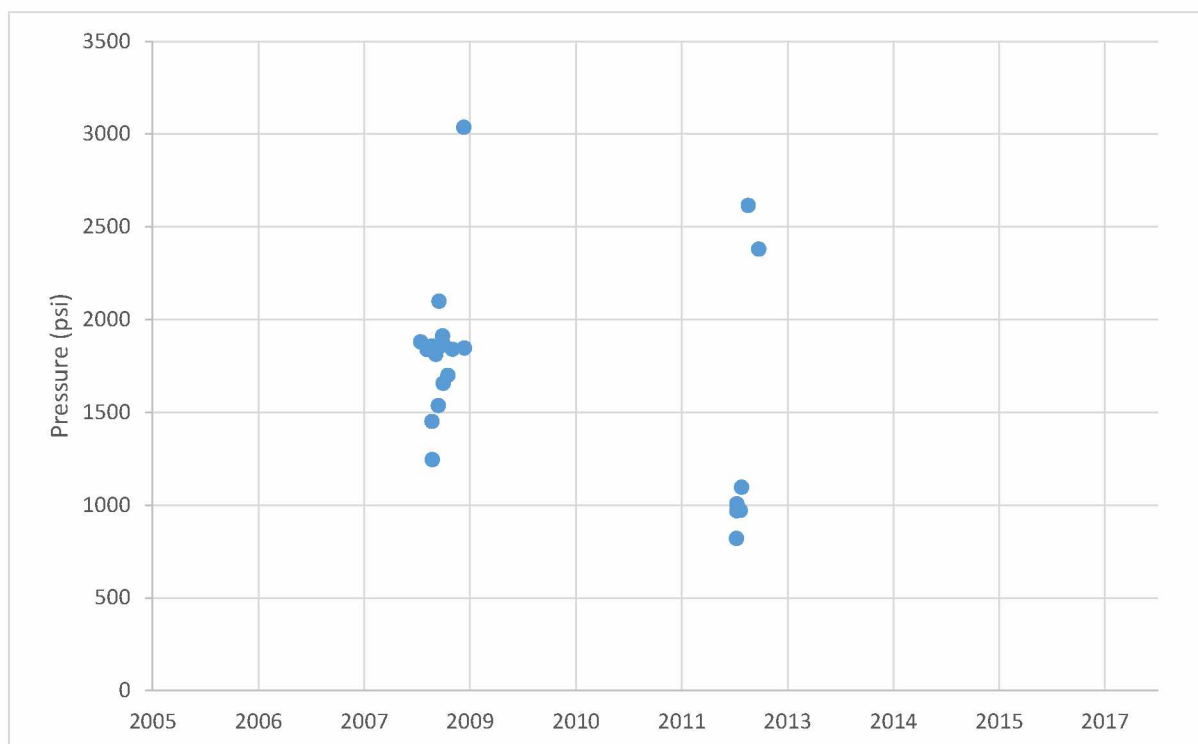


FIGURE 353: QANNIK PRESSURES

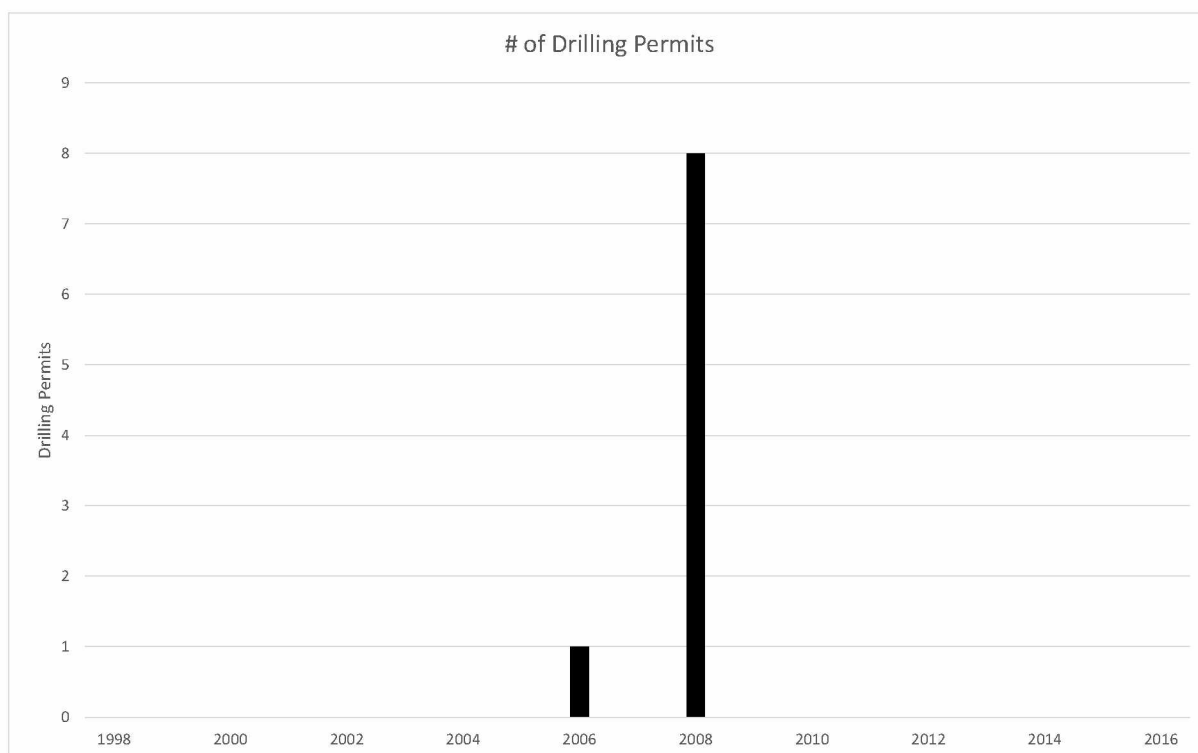


FIGURE 354: QANNIK DRILLING PERMITS BY YEAR

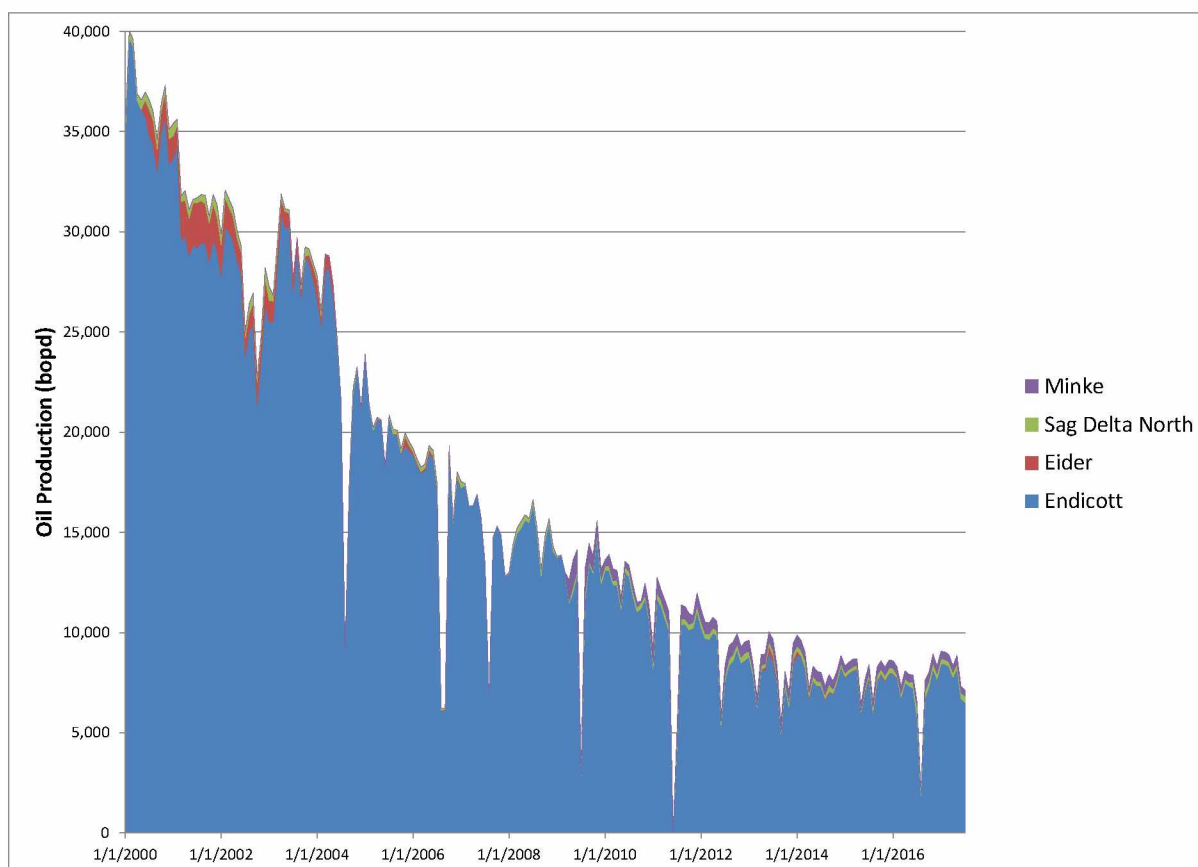


FIGURE 355: RECENT DUCK ISLAND UNIT PRODUCTION

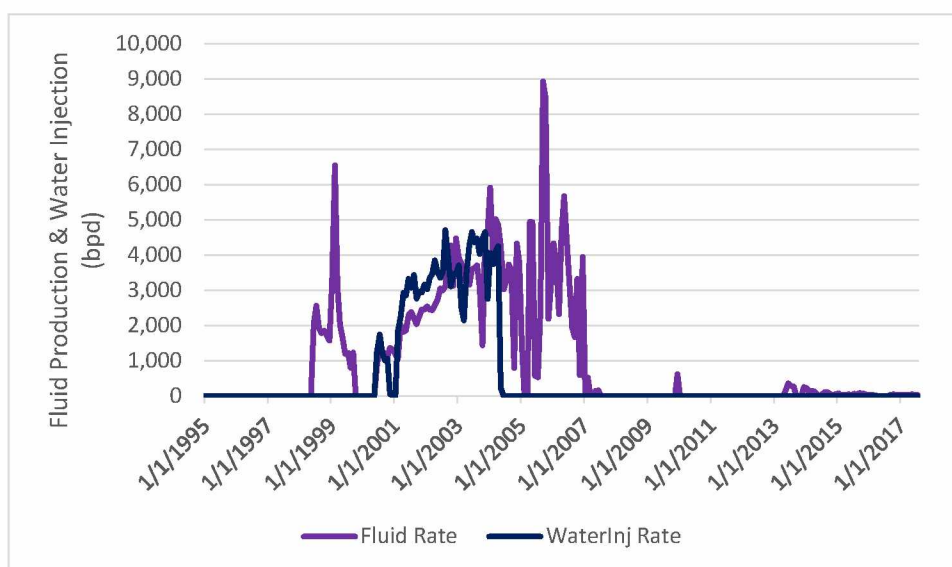


FIGURE 356: EIDER FLUID PRODUCTION AND WATER INJECTION

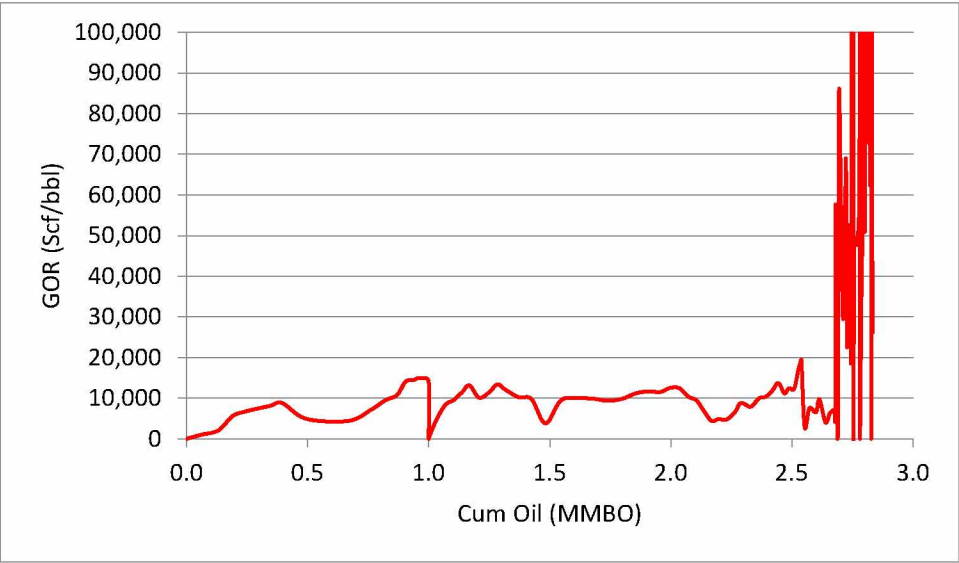


FIGURE 357: EIDER GAS OIL RATIO VS. CUM OIL

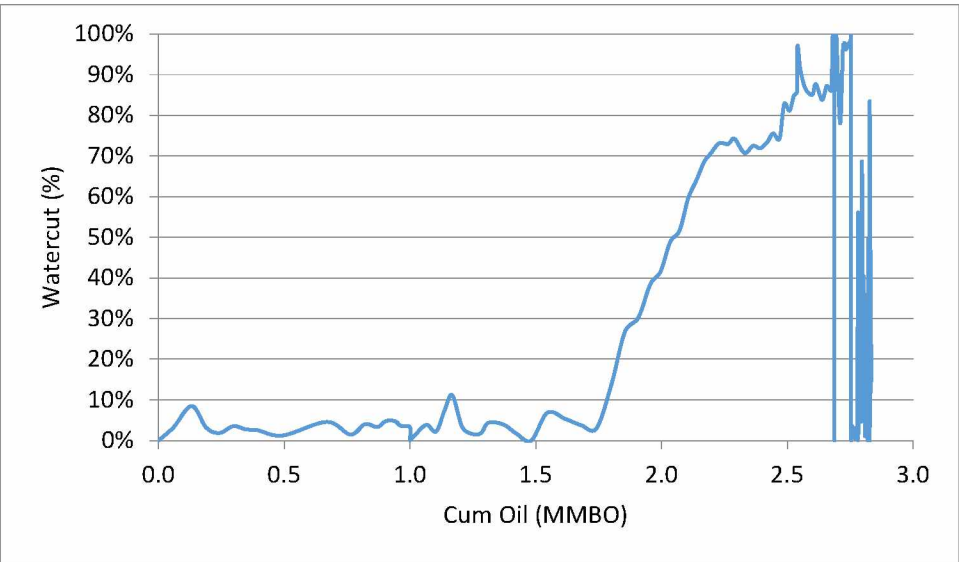


FIGURE 358: EIDER WATERCUT VS. CUM OIL

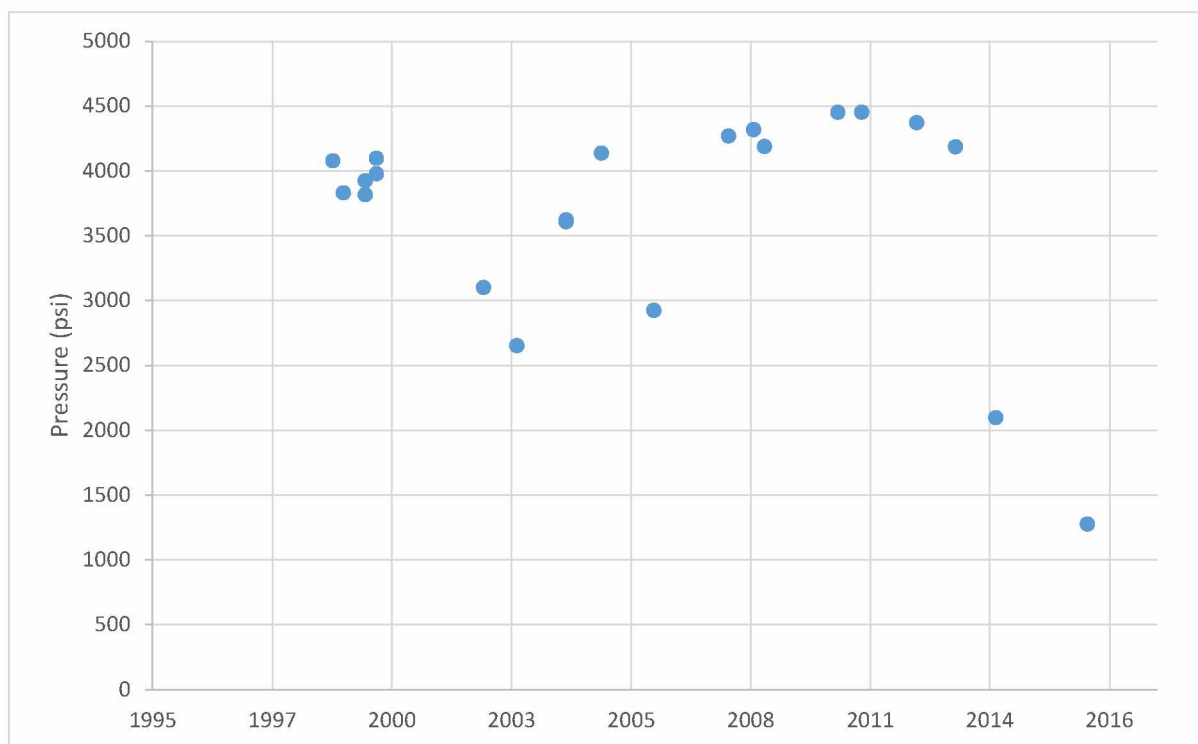


FIGURE 359: EIDER PRESSURES

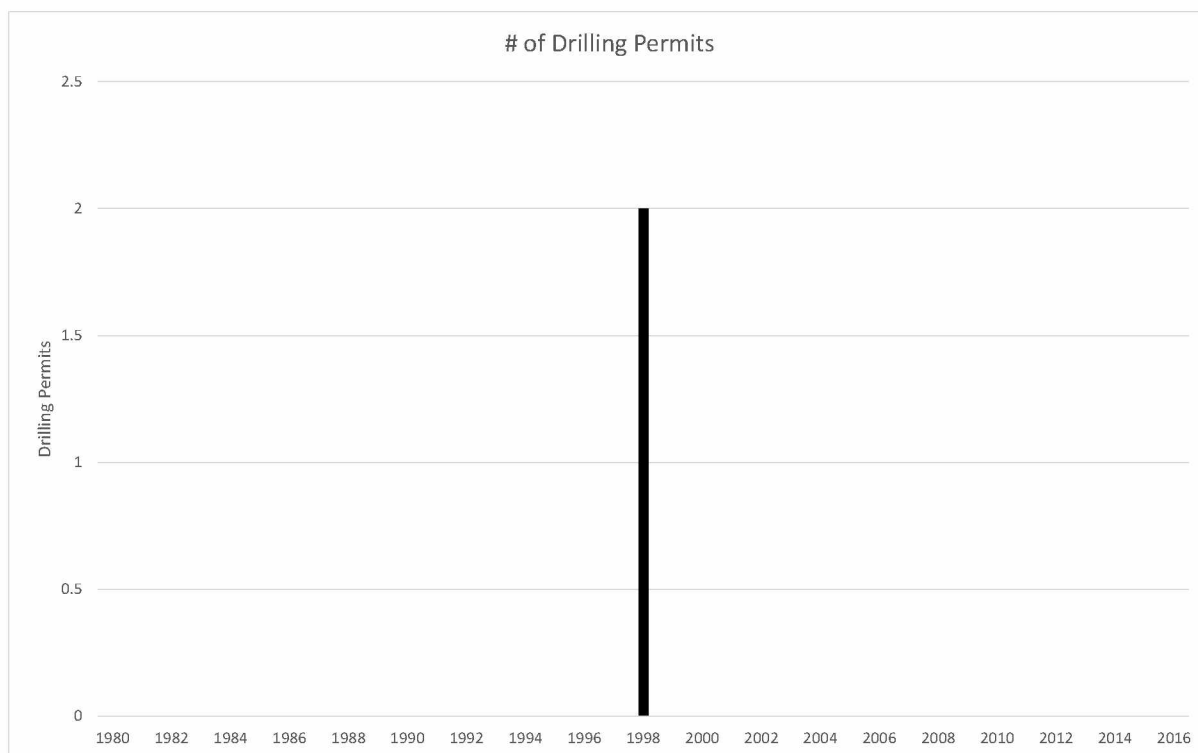


FIGURE 360: EIDER DRILLING PERMITS BY YEAR

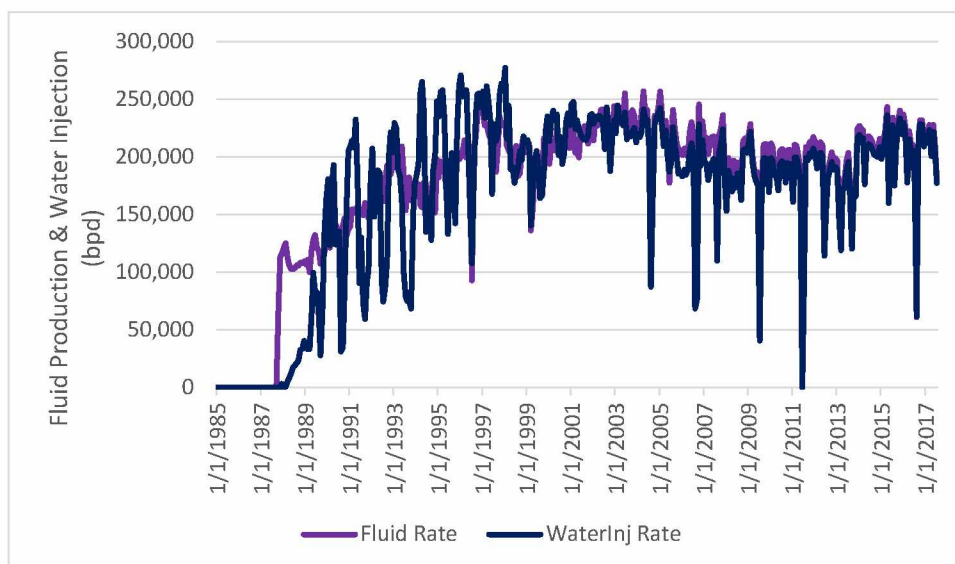


FIGURE 361: ENDICOTT FLUID PRODUCTION AND WATER INJECTION RATE

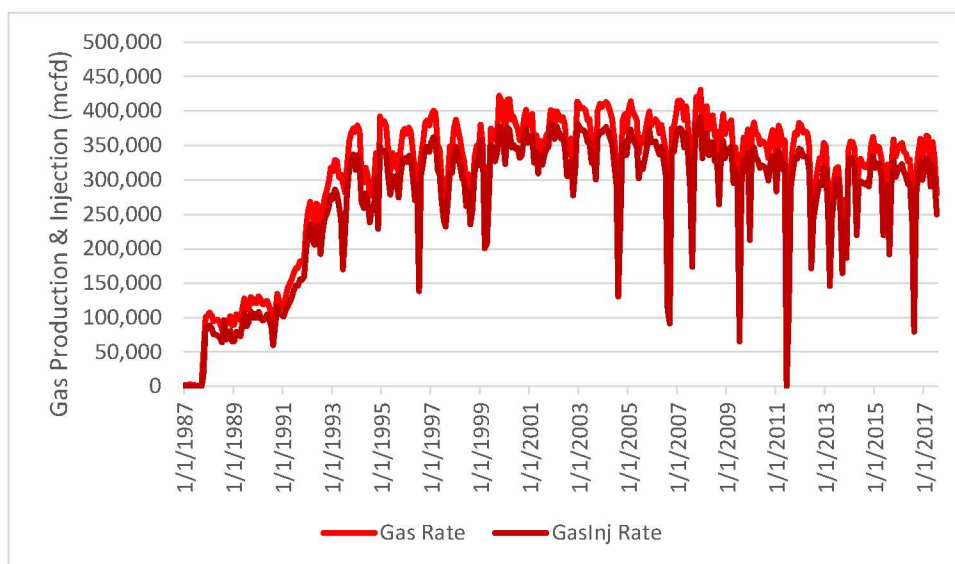


FIGURE 362: ENDICOTT GAS PRODUCTION AND INJECTION



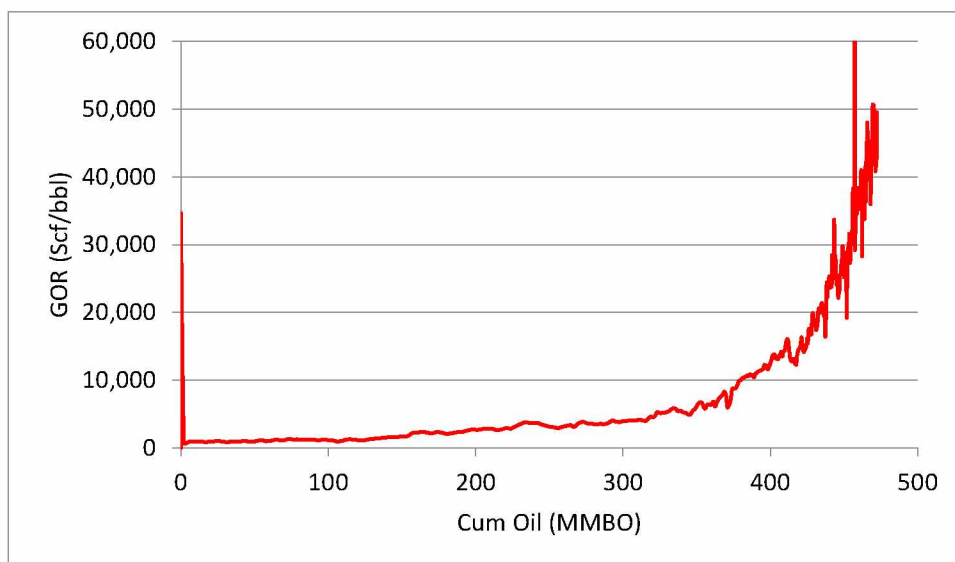


FIGURE 363: ENDICOTT GAS OIL RATIO VS. CUM OIL

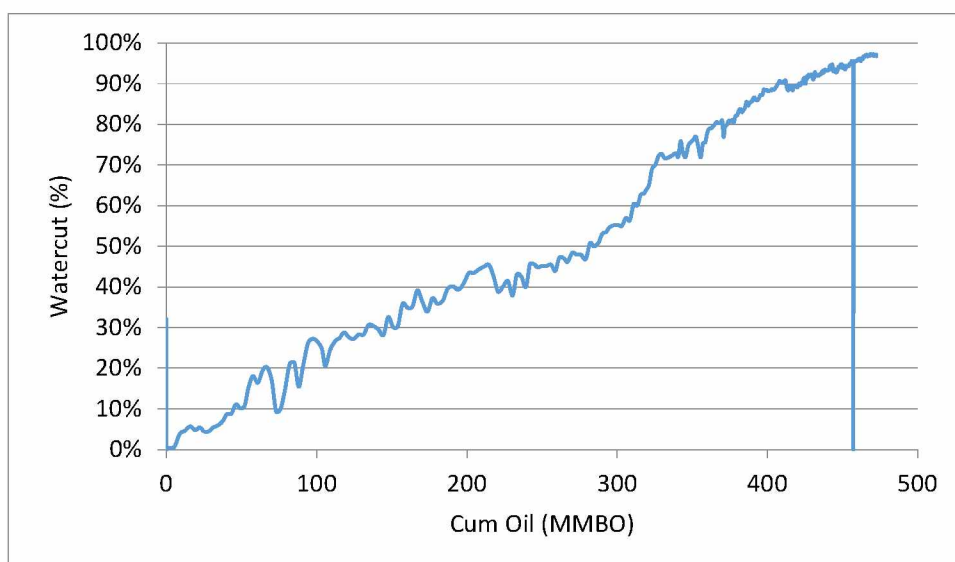


FIGURE 364: ENDICOTT WATERCUT VS. CUM OIL

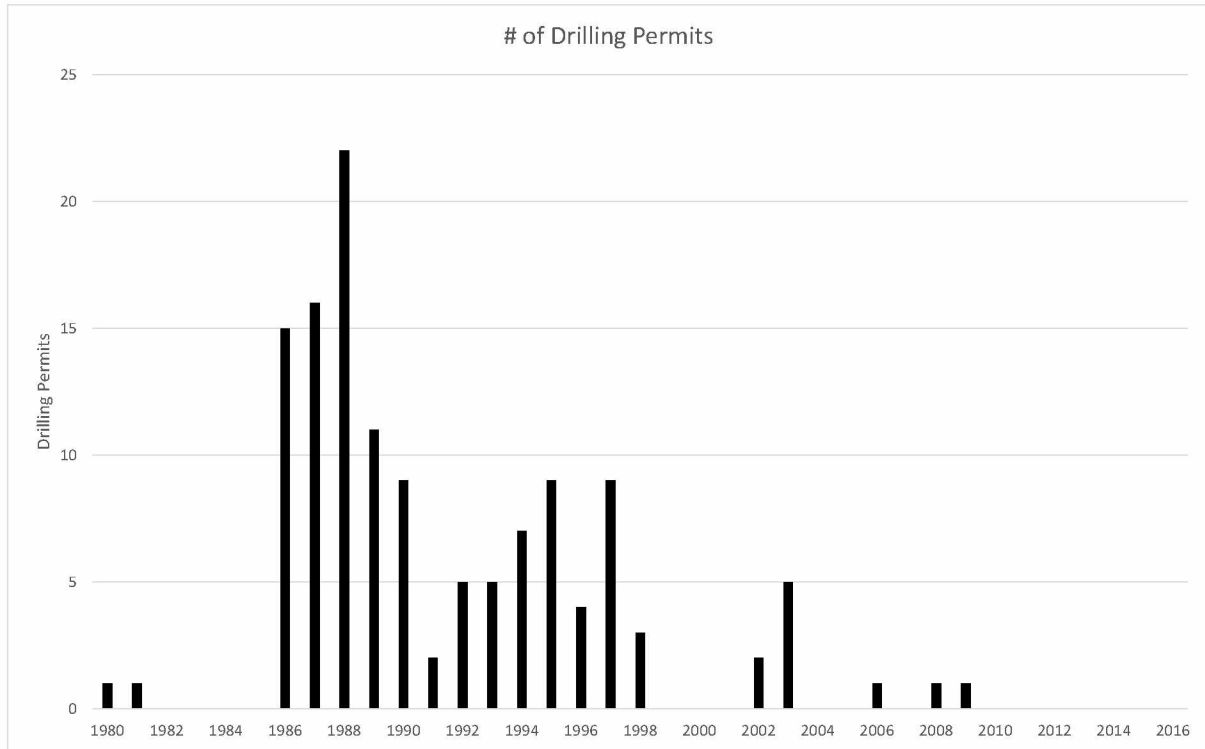


FIGURE 365: ENDICOTT DRILLING PERMITS BY YEAR

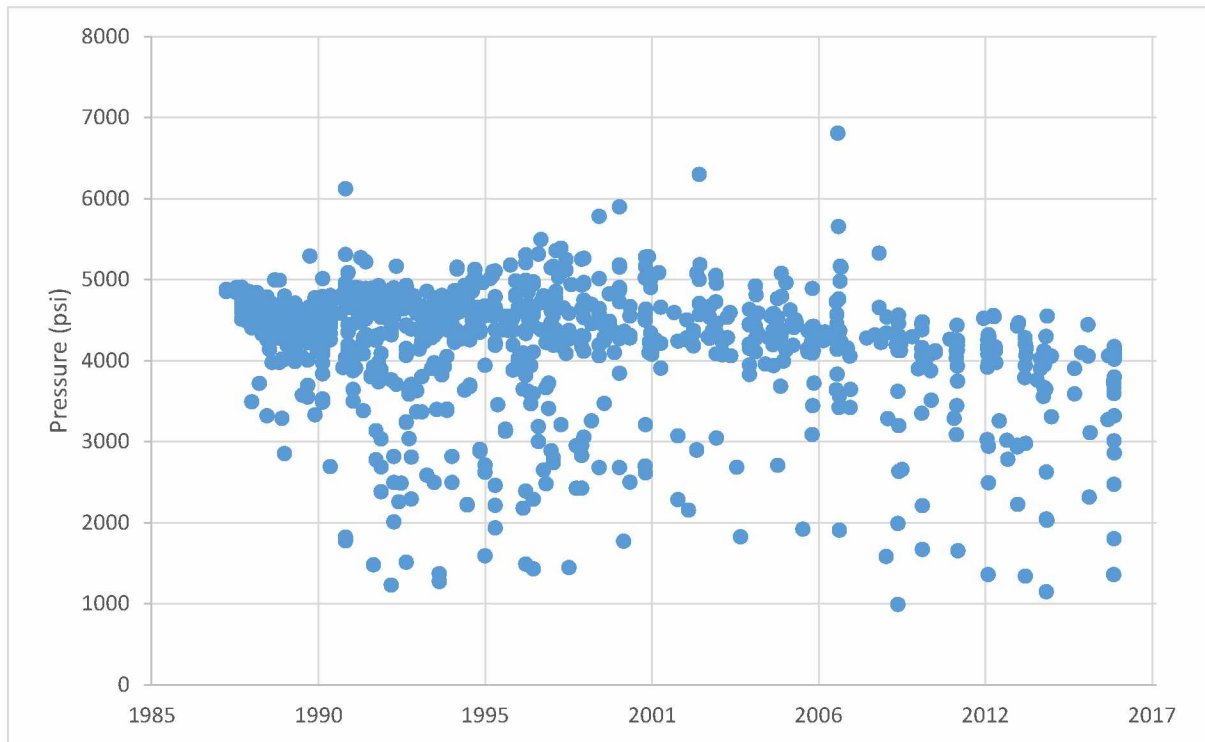


FIGURE 366: ENDICOTT PRESSURES

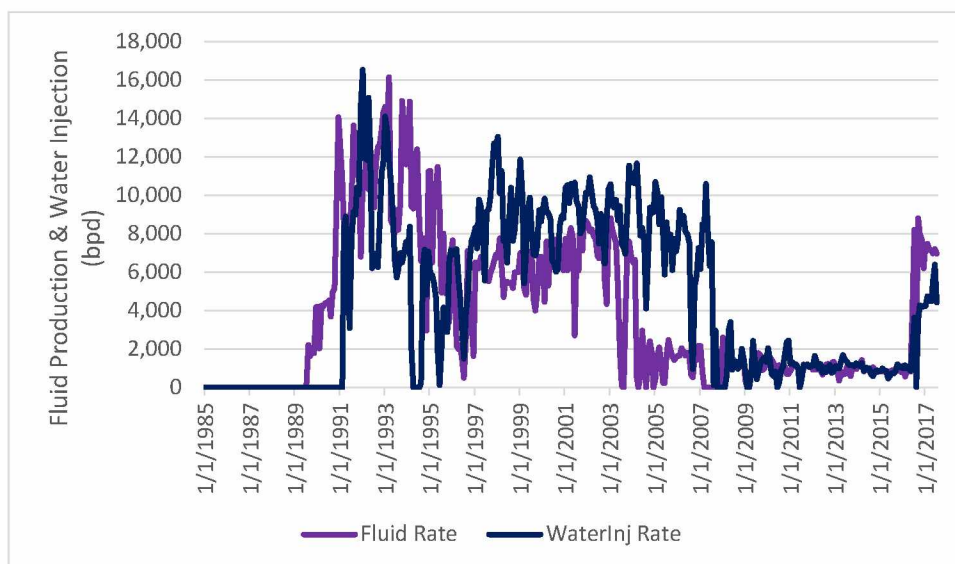


FIGURE 367: SAG DELTA NORTH FLUID PRODUCTION AND WATER INJECTION RATE

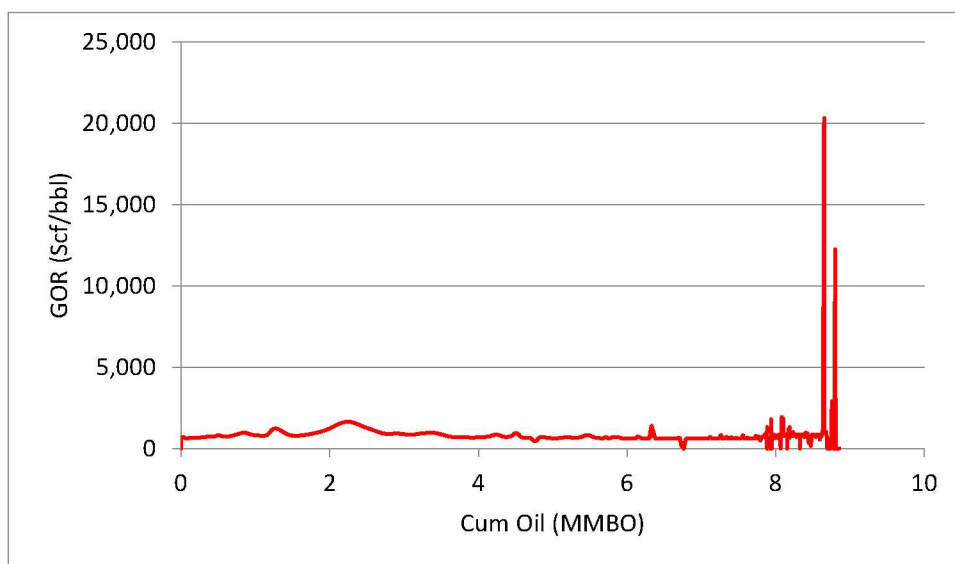


FIGURE 368: SAG DELTA NORTH GOR VS. CUM OIL

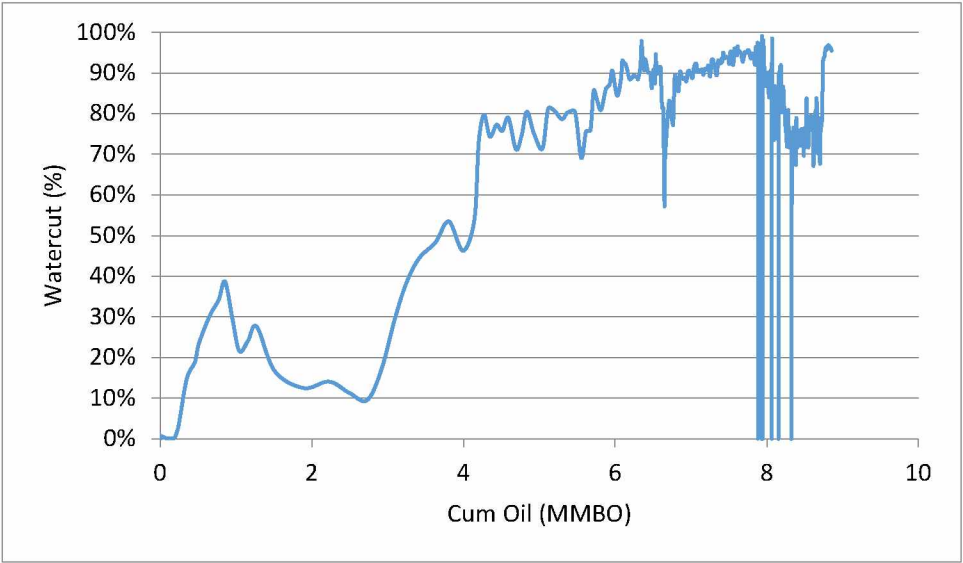


FIGURE 369: SAG DELTA NORTH WATERCUT VS. CUM OIL

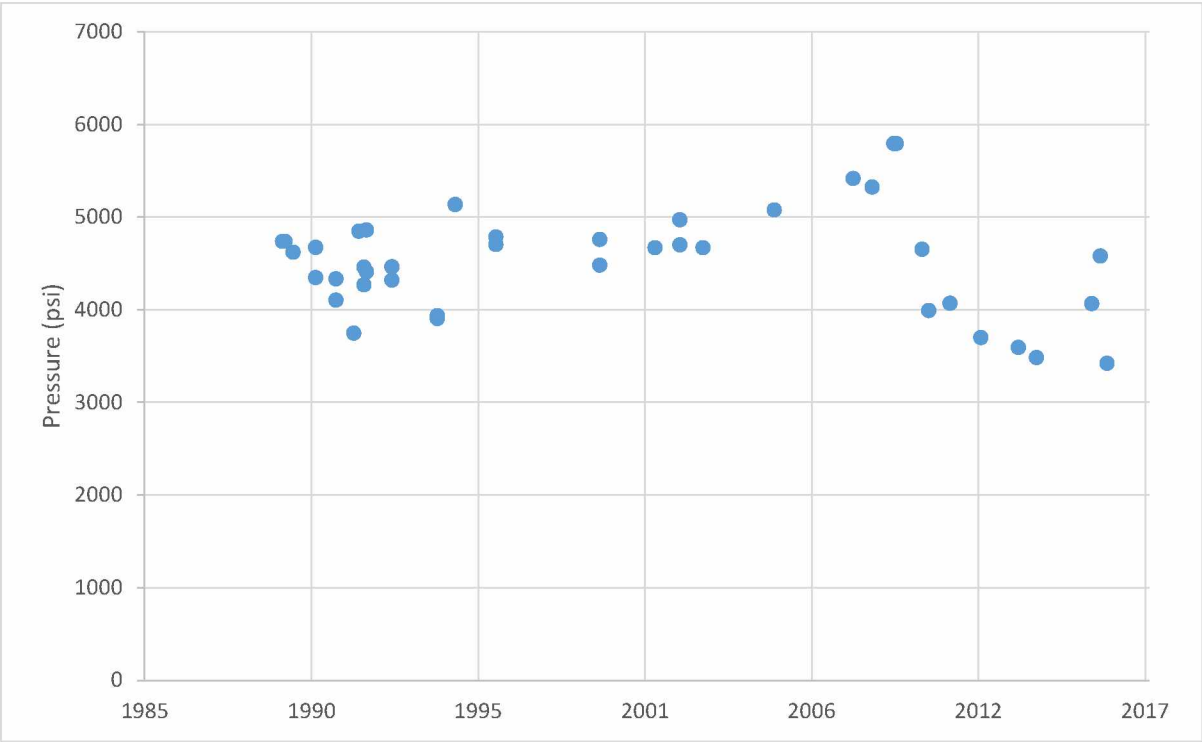


FIGURE 370: SAG DELTA NORTH PRESSURES

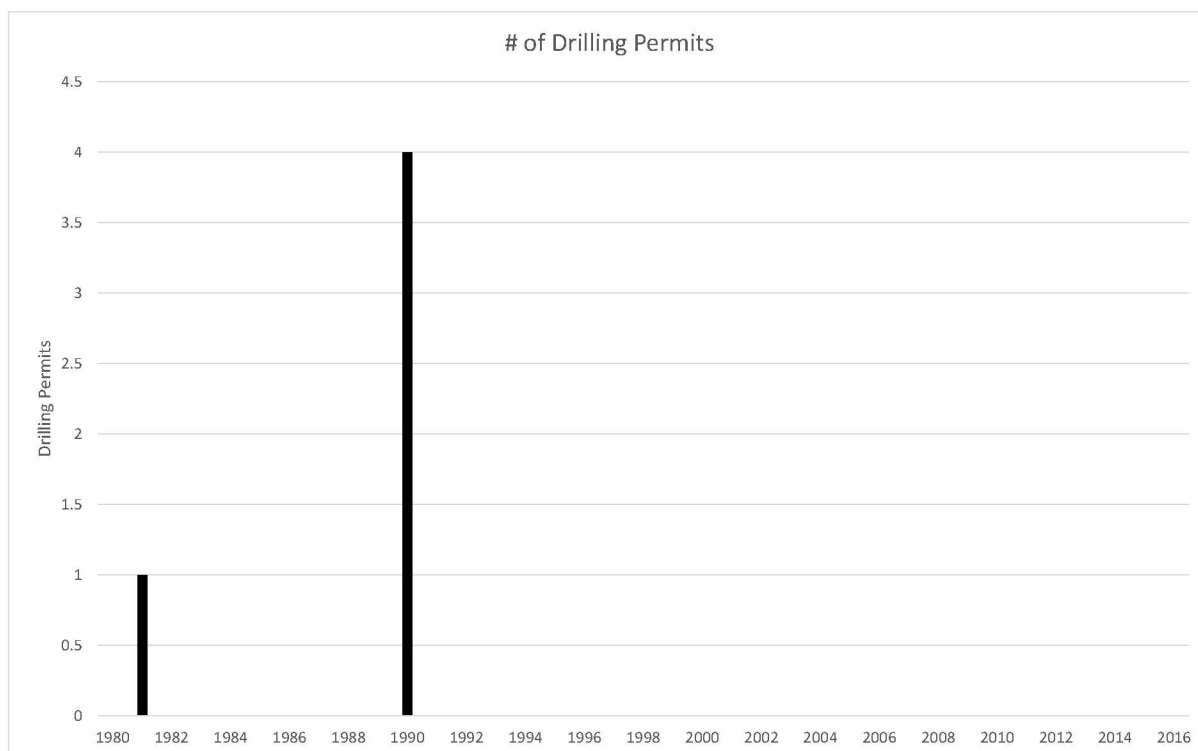


FIGURE 371: SAG DELTA NORTH DRILLING PERMITS BY YEAR

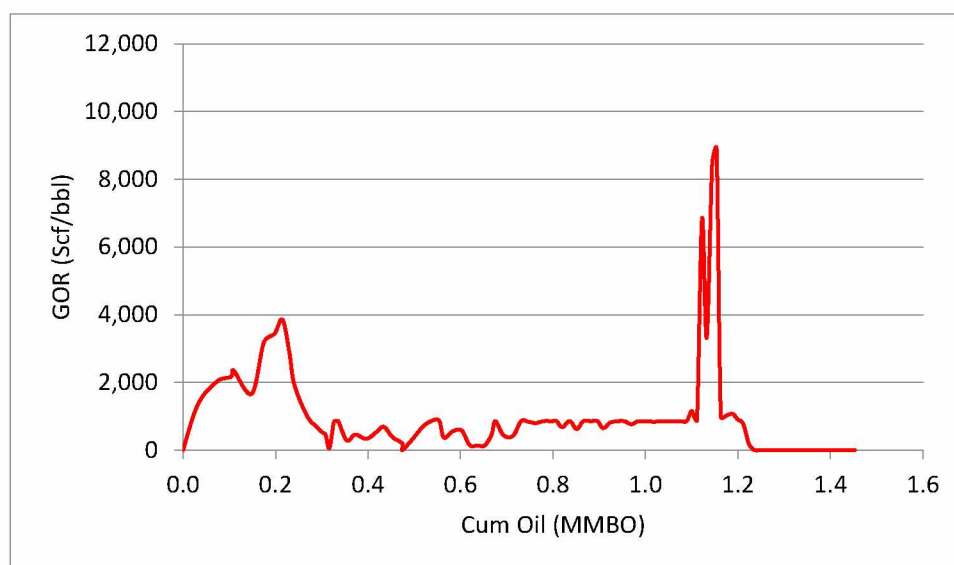


FIGURE 372: MINKE GAS OIL RATIO VS. CUM OIL

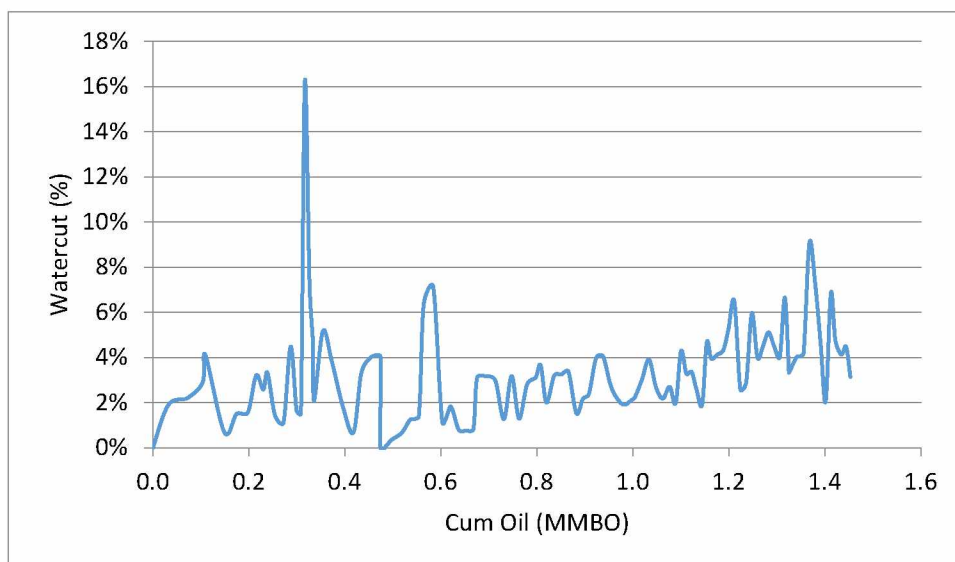


FIGURE 373: MINKE WATERCUT VS. CUM OIL

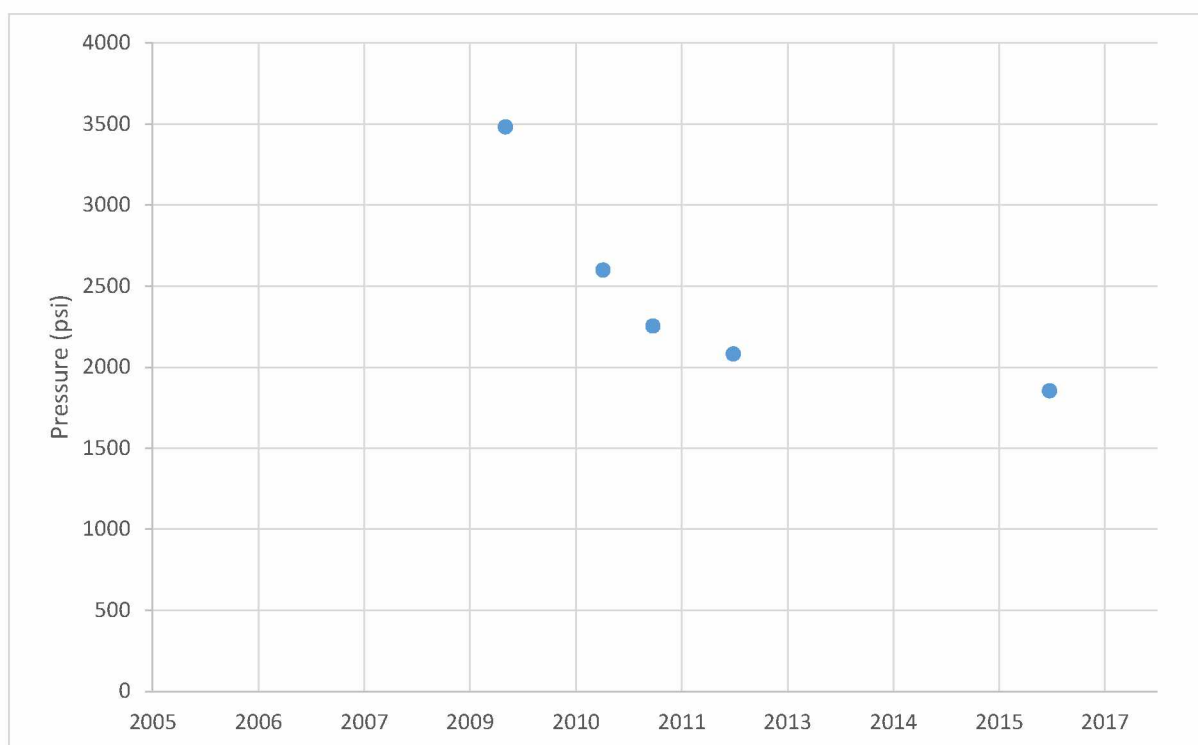


FIGURE 374: MINKE PRESSURES



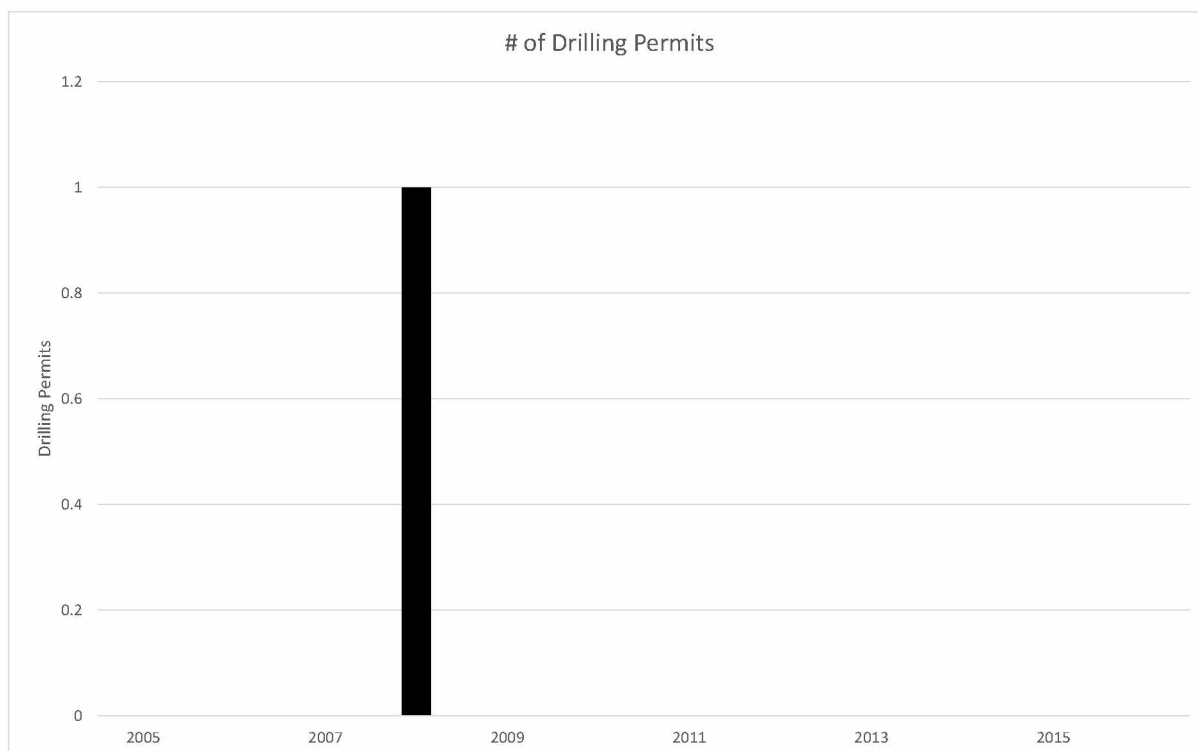


FIGURE 375: MINKE DRILLING PERMITS BY YEAR

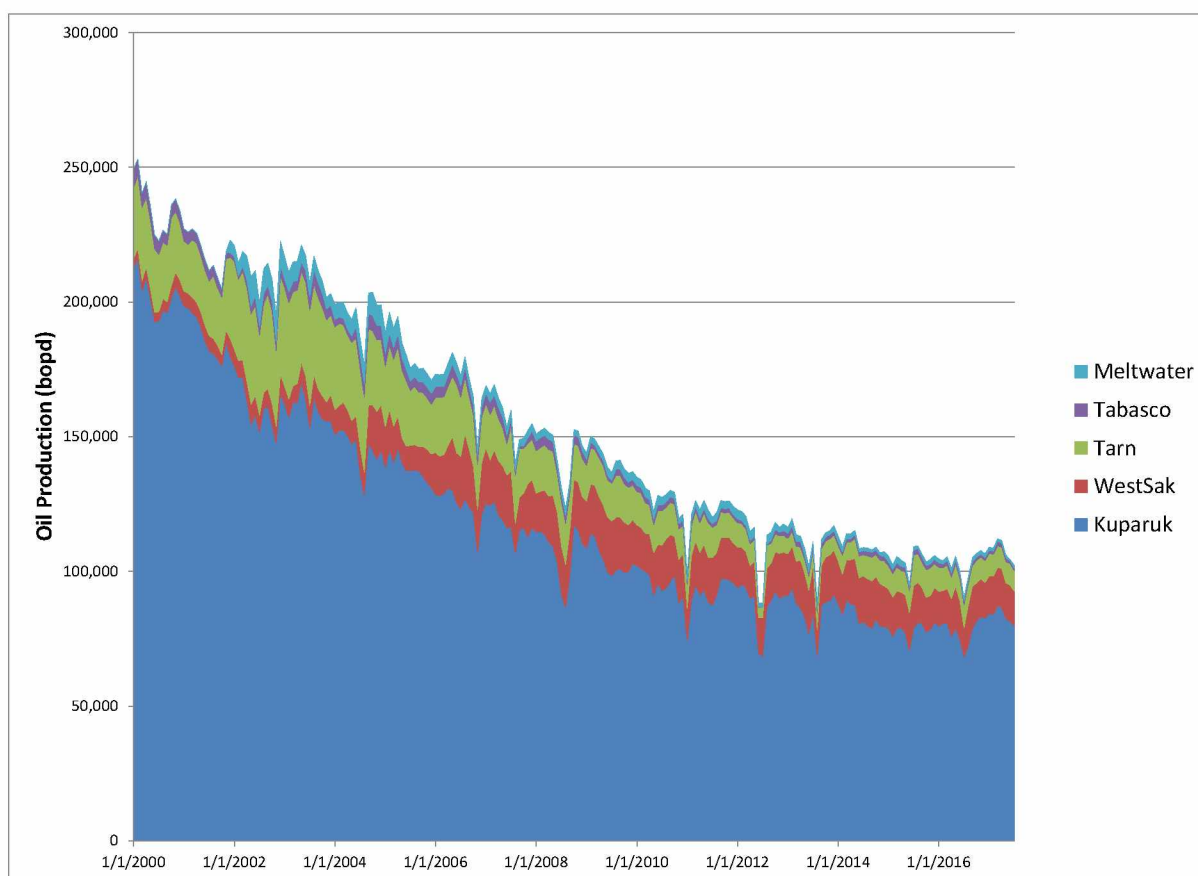


FIGURE 376: RECENT KUPARUK RIVER UNIT PRODUCTION

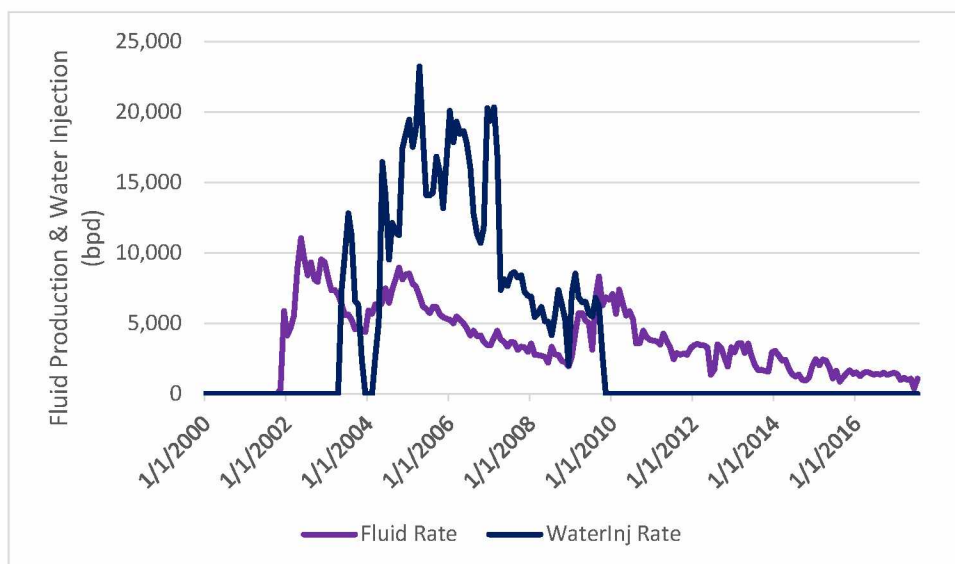


FIGURE 377: MELTWATER FLUID PRODUCTION AND WATER INJECTION

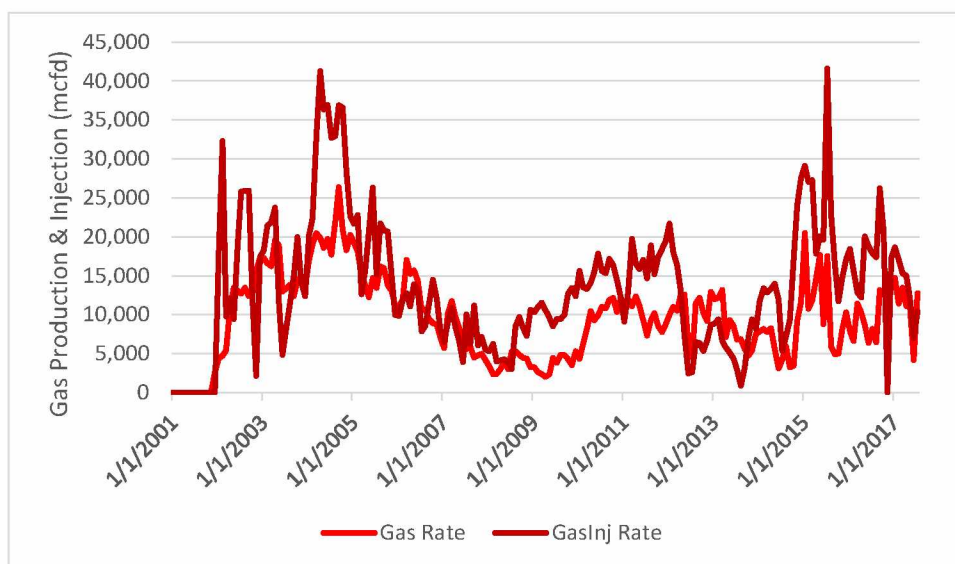


FIGURE 378: MELTWATER GAS PRODUCTION AND INJECTION RATE

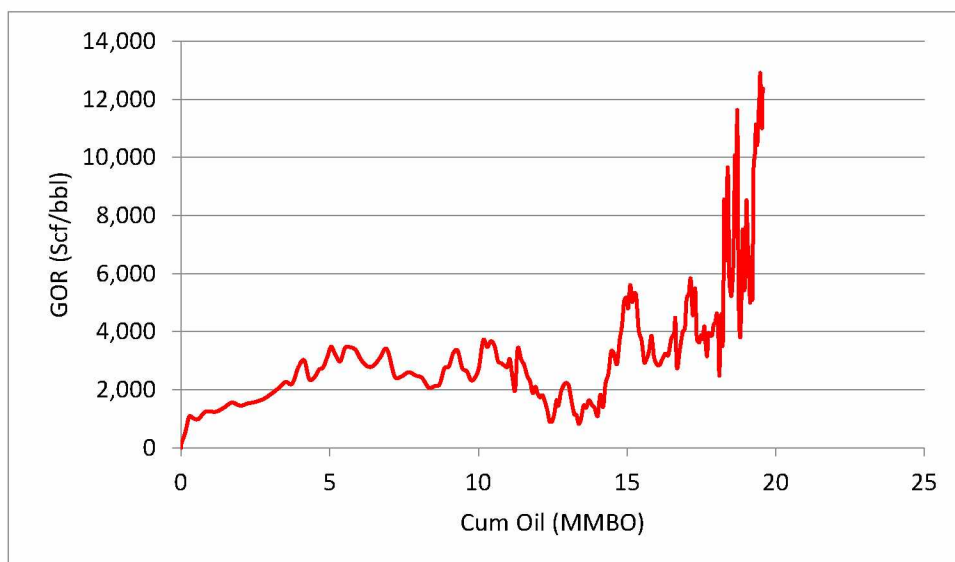


FIGURE 379: MELTWATER GAS OIL RATIO VS. CUM OIL

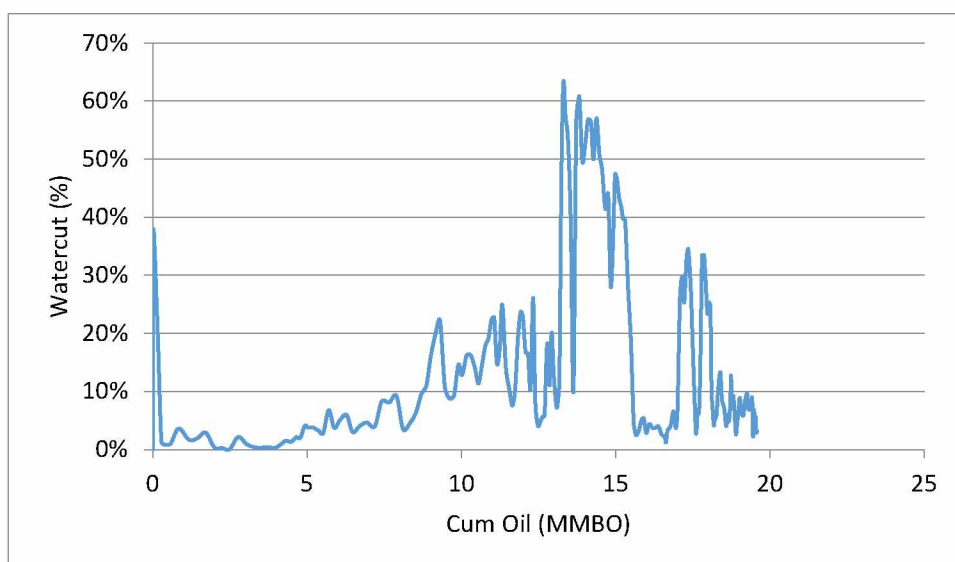


FIGURE 380: MELTWATER WATERCUT VS. CUM OIL

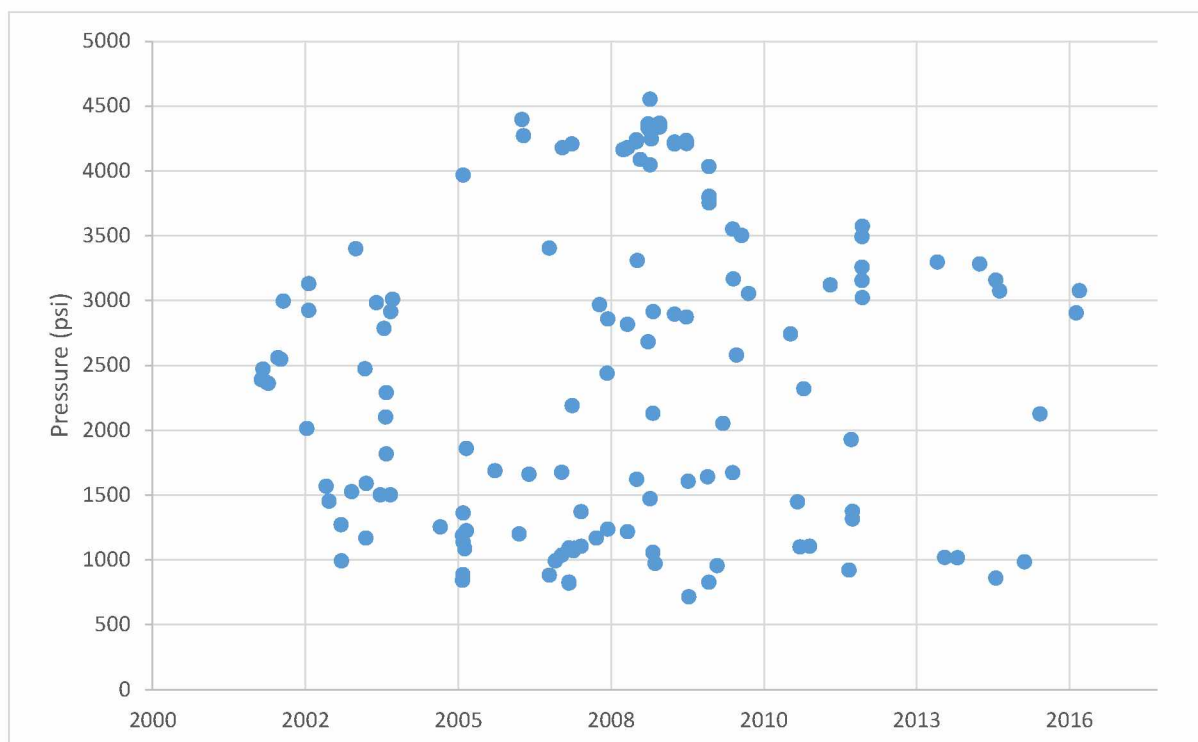


FIGURE 381: MELTWATER PRESSURES

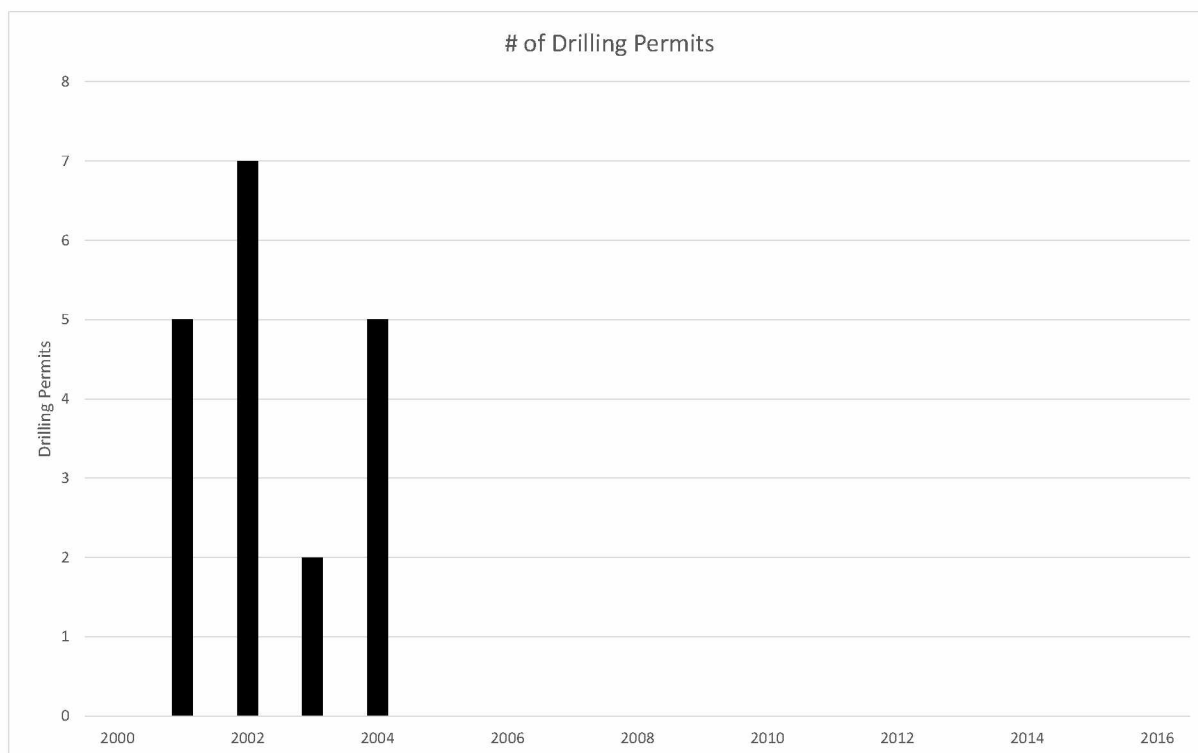


FIGURE 382: MELTWATER DRILLING PERMITS BY YEAR

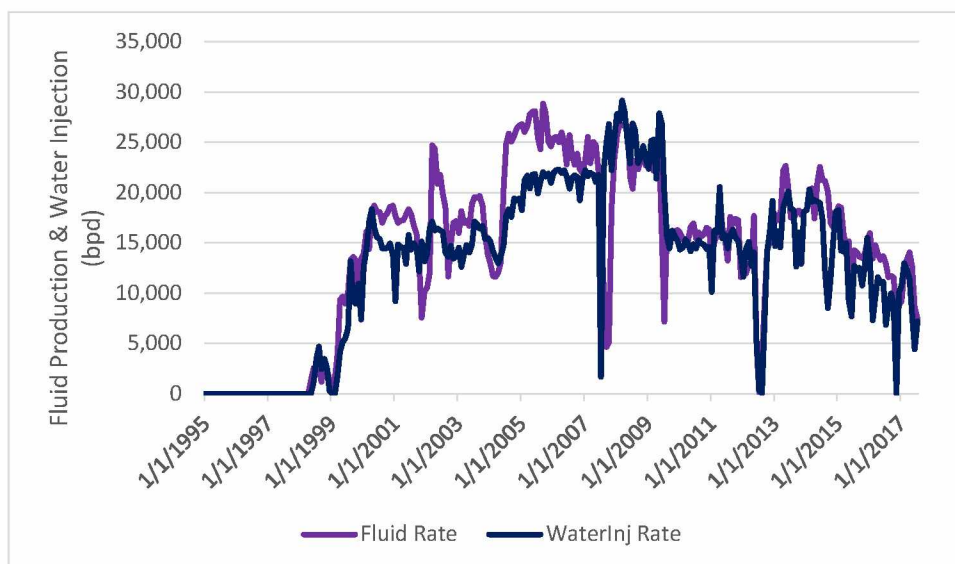


FIGURE 383: TABASCO FLUID PRODUCTION AND WATER INJECTION

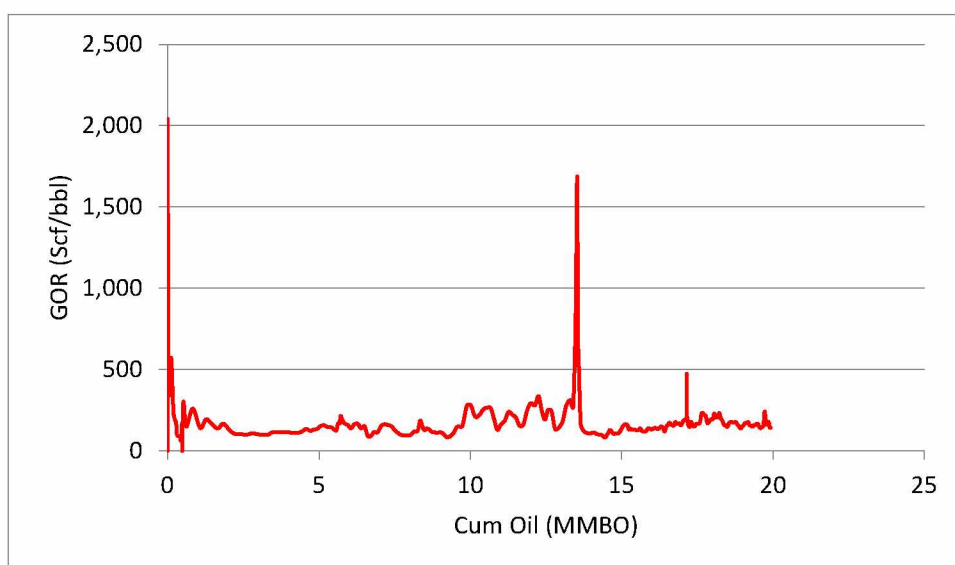


FIGURE 384: TABASCO GAS OIL RATIO VS. CUM OIL

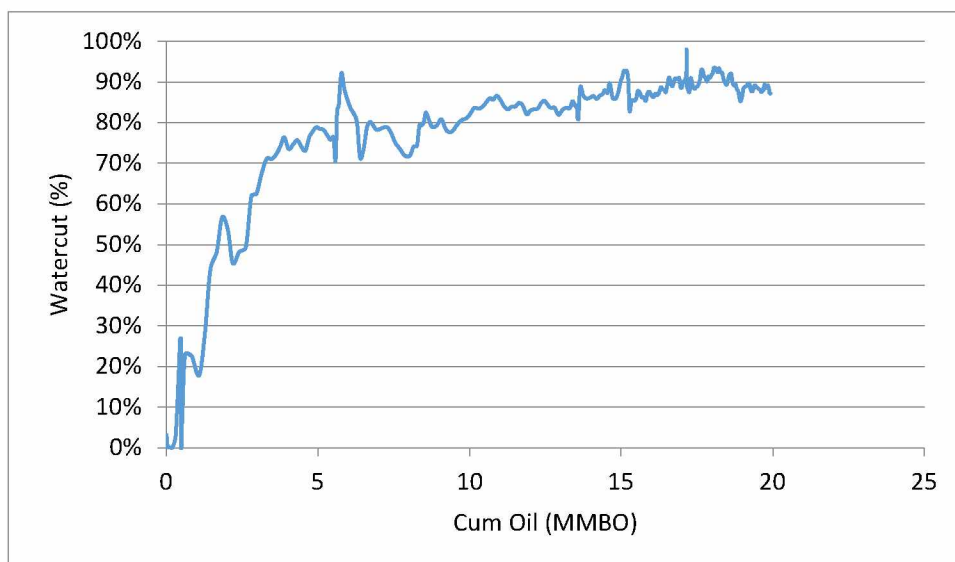


FIGURE 385: TABASCO WATERCUT VS. CUM OIL

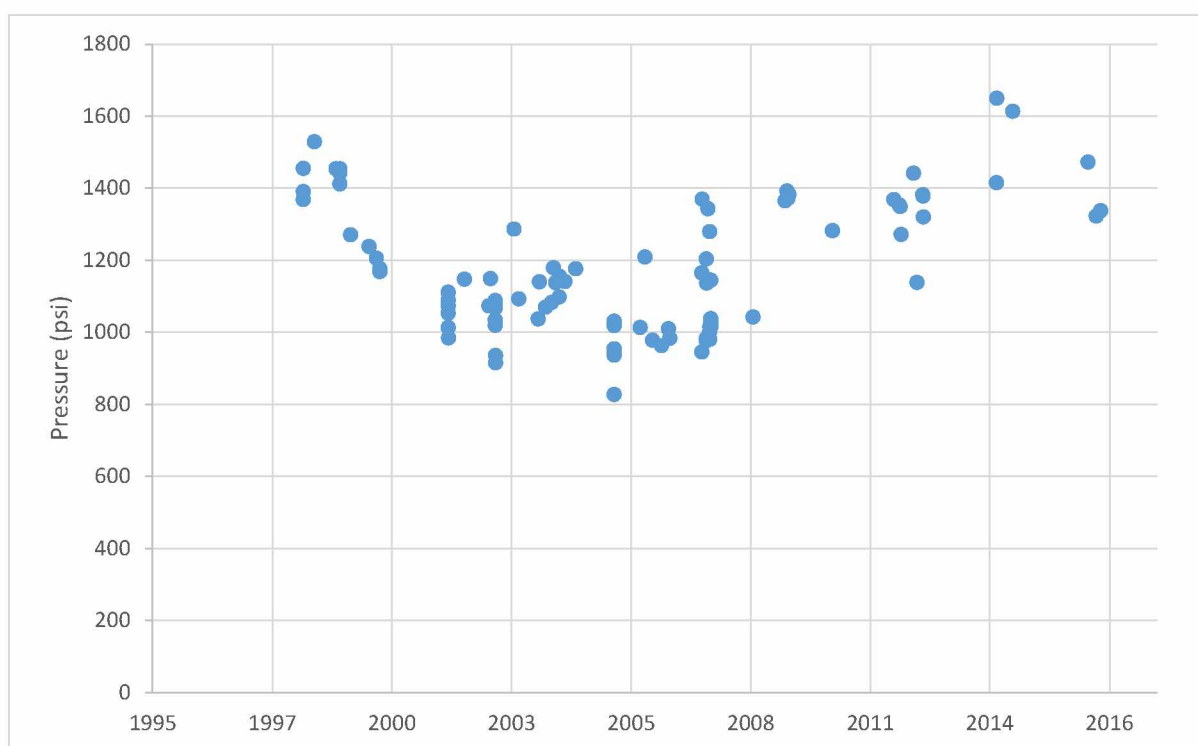


FIGURE 386: TABASCO PRESSURES



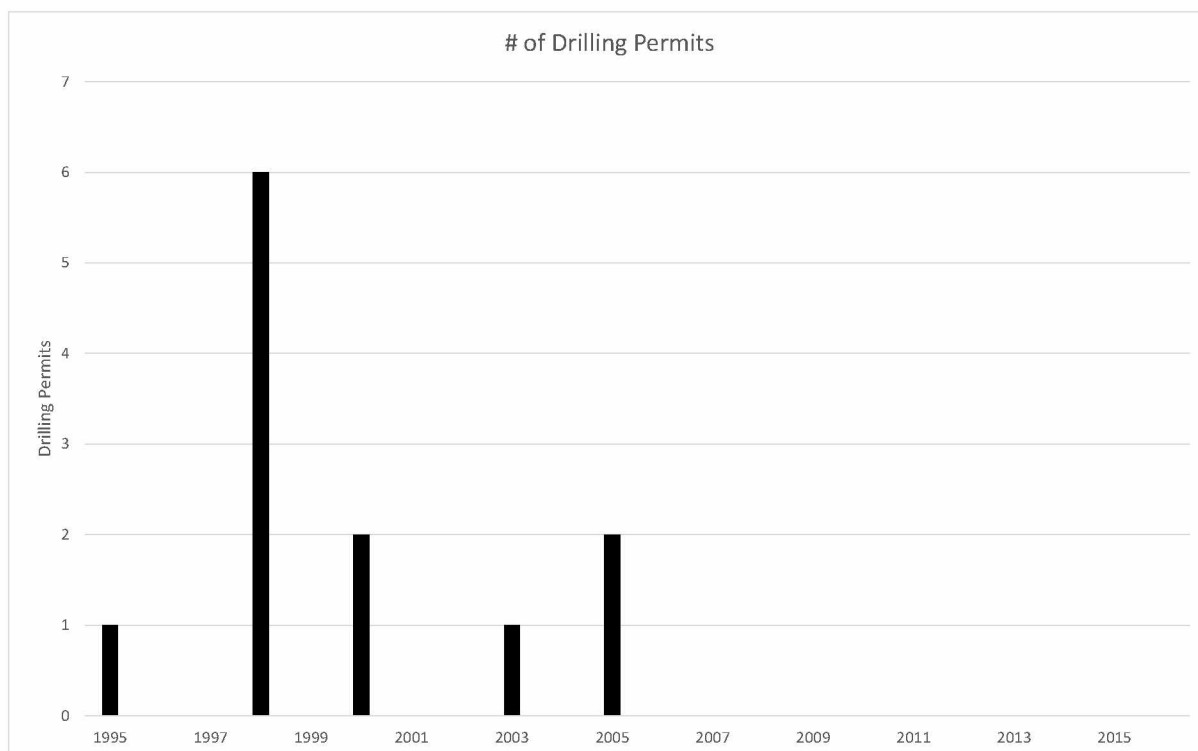


FIGURE 387: TABASCO PRESSURES BY YEAR

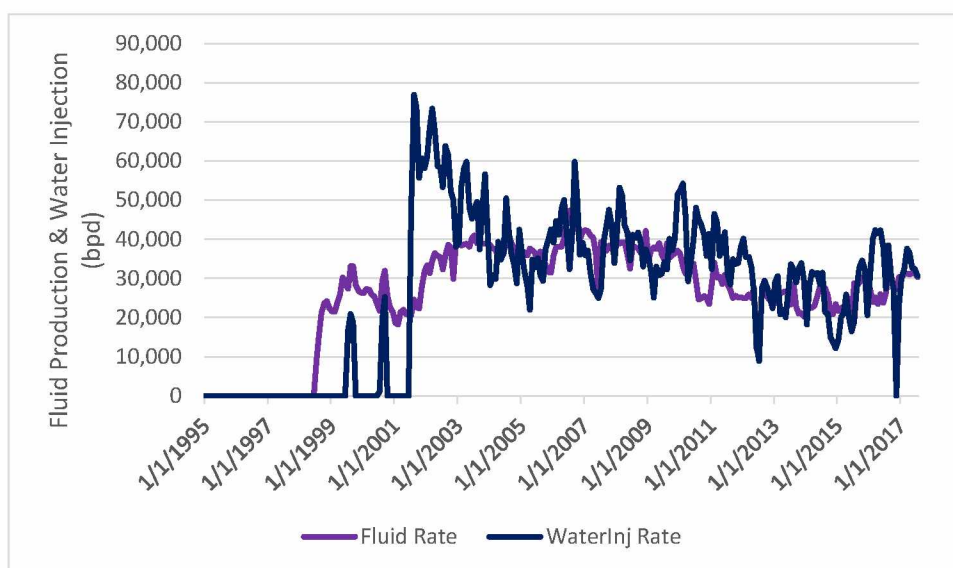


FIGURE 388: TARN FLUID PRODUCTION AND WATER INJECTION

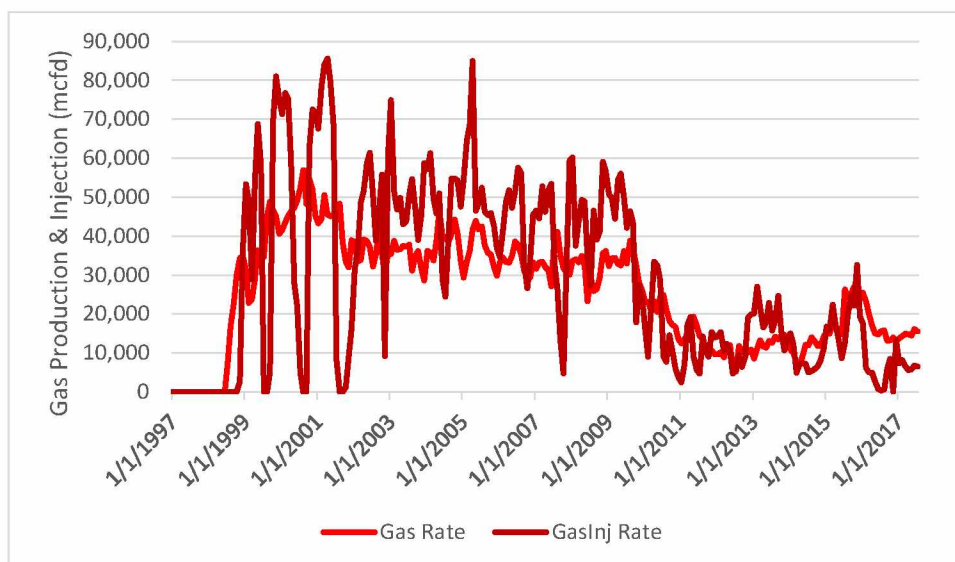


FIGURE 389: TARN GAS PRODUCTION AND INJECTION

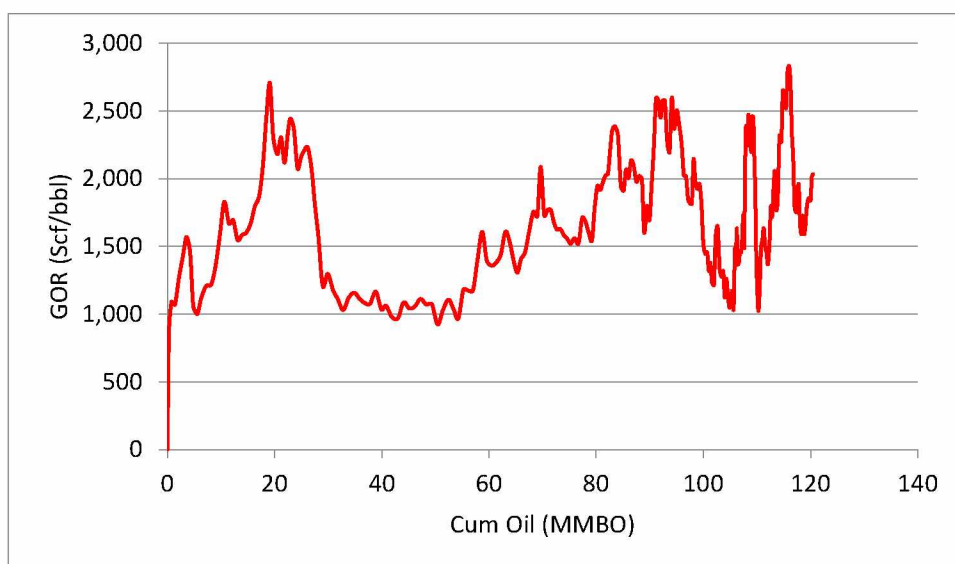


FIGURE 390: TARN GAS OIL RATIO VS. CUM OIL

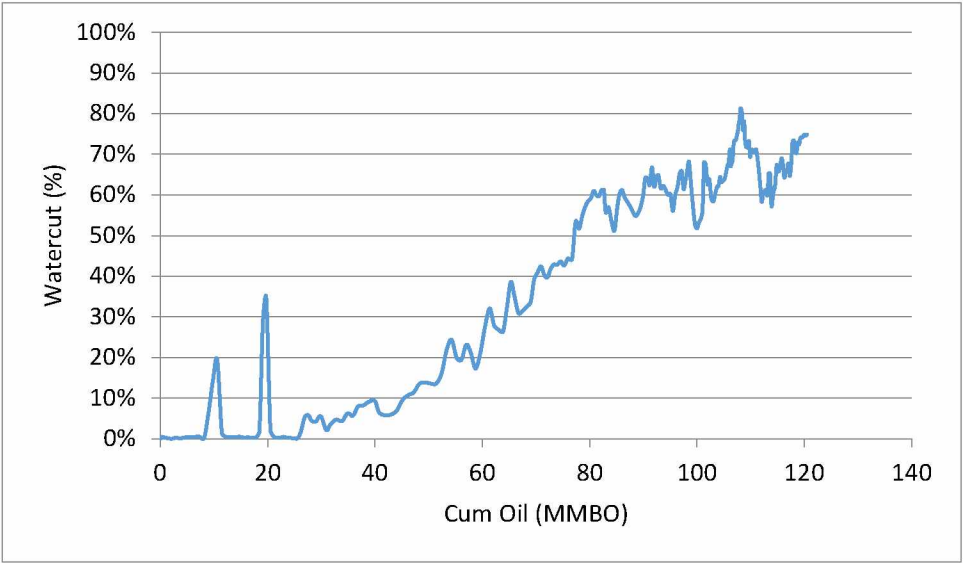


FIGURE 391: TARN WATERCUT VS. CUM OIL

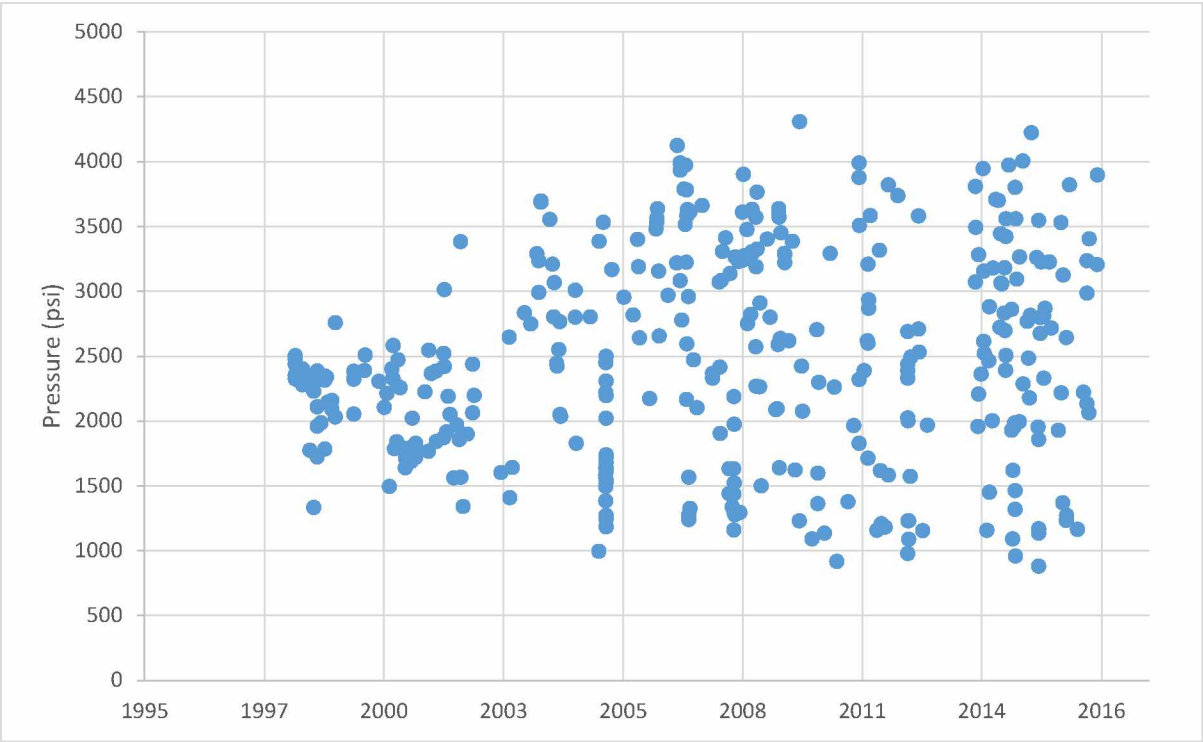


FIGURE 392: TARN PRESSURES

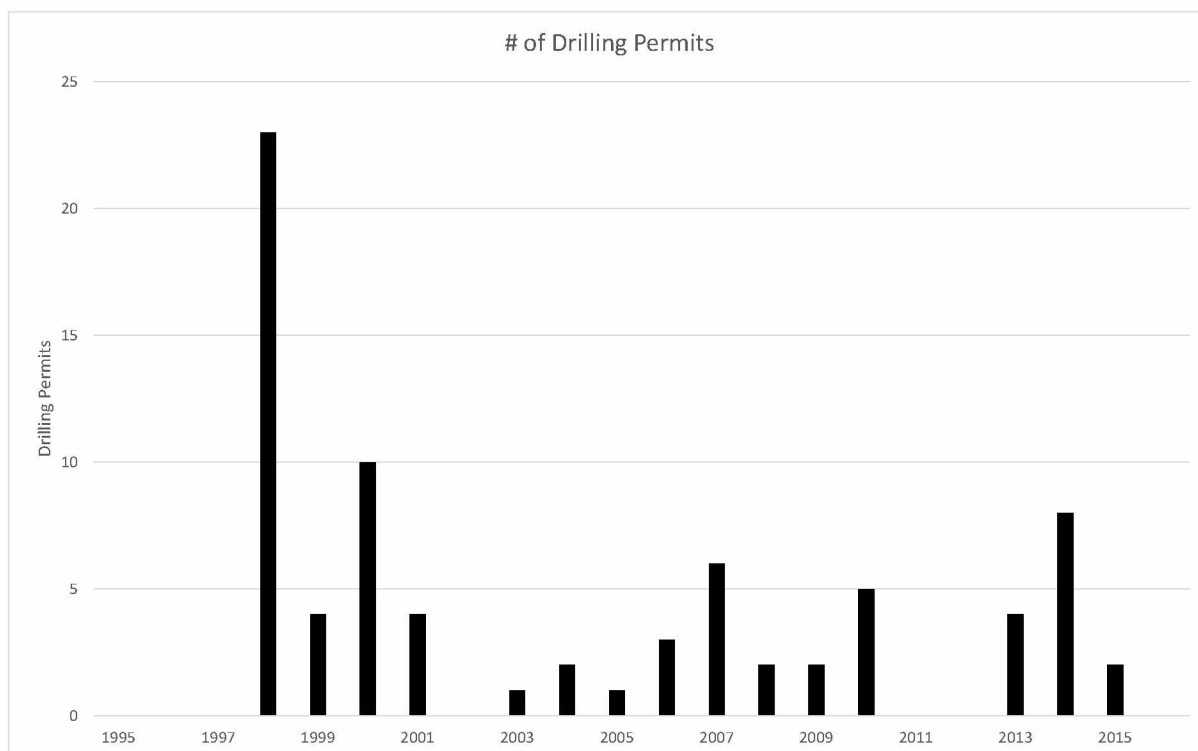


FIGURE 393: TARN DRILLING PERMITS BY YEAR

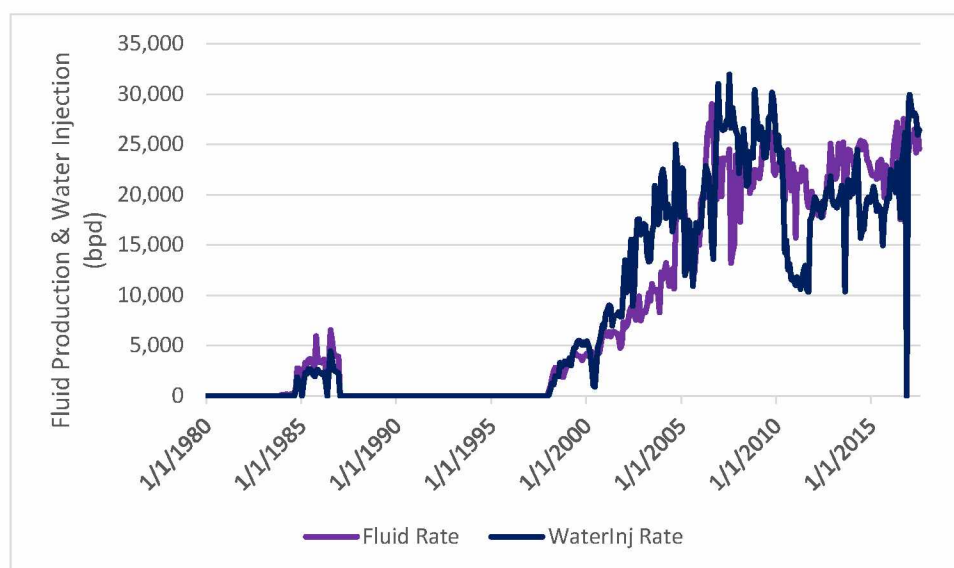


FIGURE 394: WEST SAK FLUID PRODUCTION AND WATER INJECTION

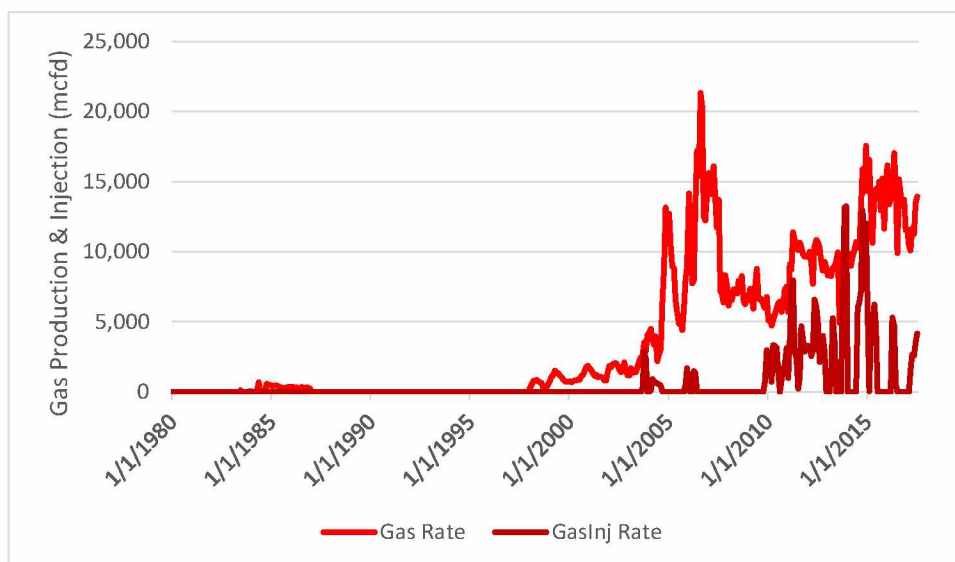


FIGURE 395: WEST SAK GAS PRODUCTION AND INJECTION

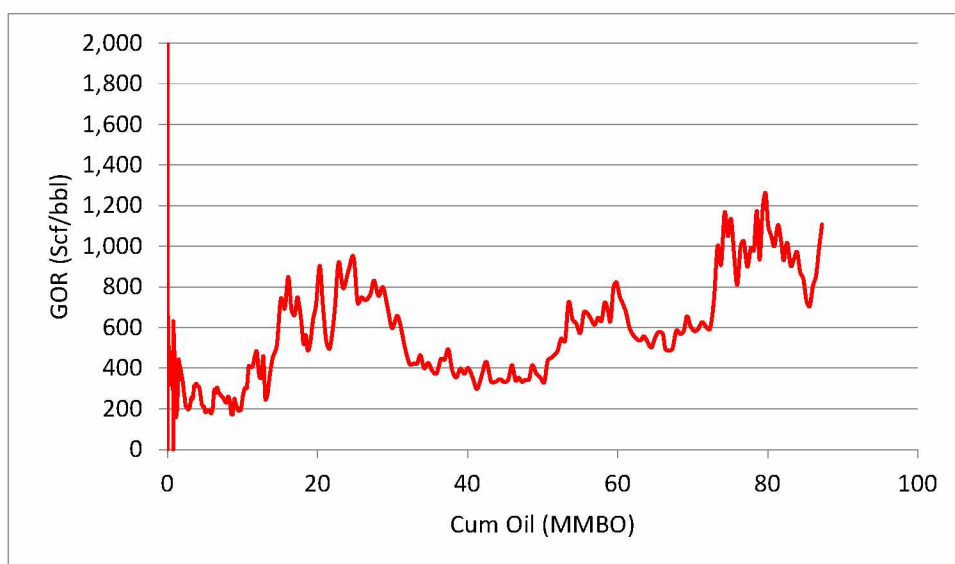


FIGURE 396: WEST SAK GAS OIL RATIO VS. CUM OIL

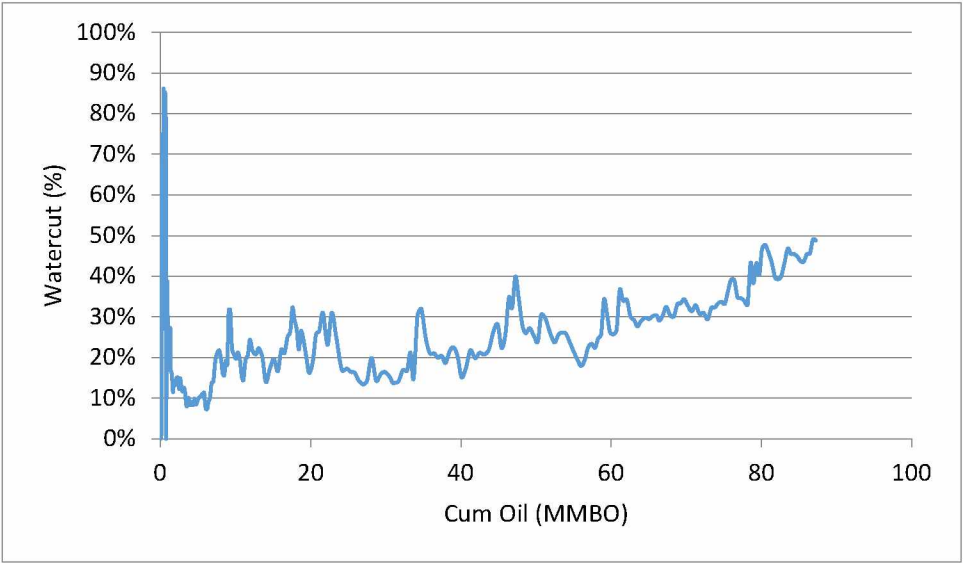


FIGURE 397: WEST SAK WATERCUT VS. CUM OIL

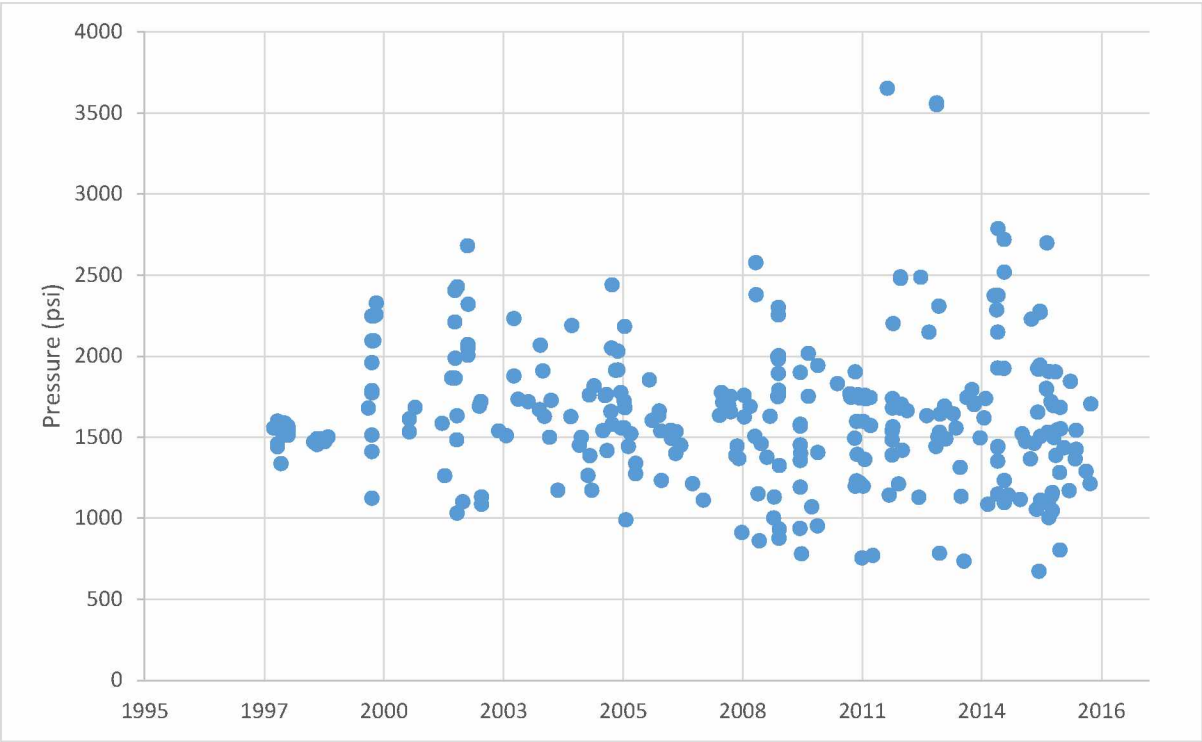


FIGURE 398: WEST SAK PRESSURES



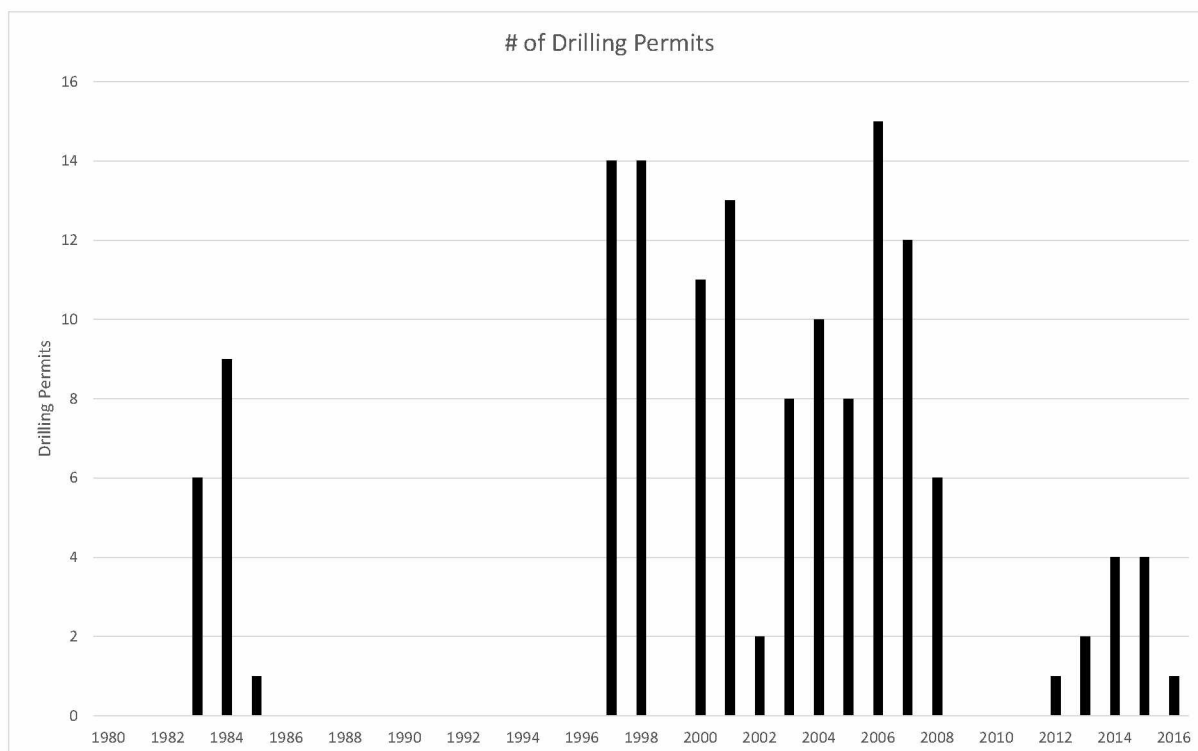


FIGURE 399: WEST SAK DRILLING PERMITS BY YEAR

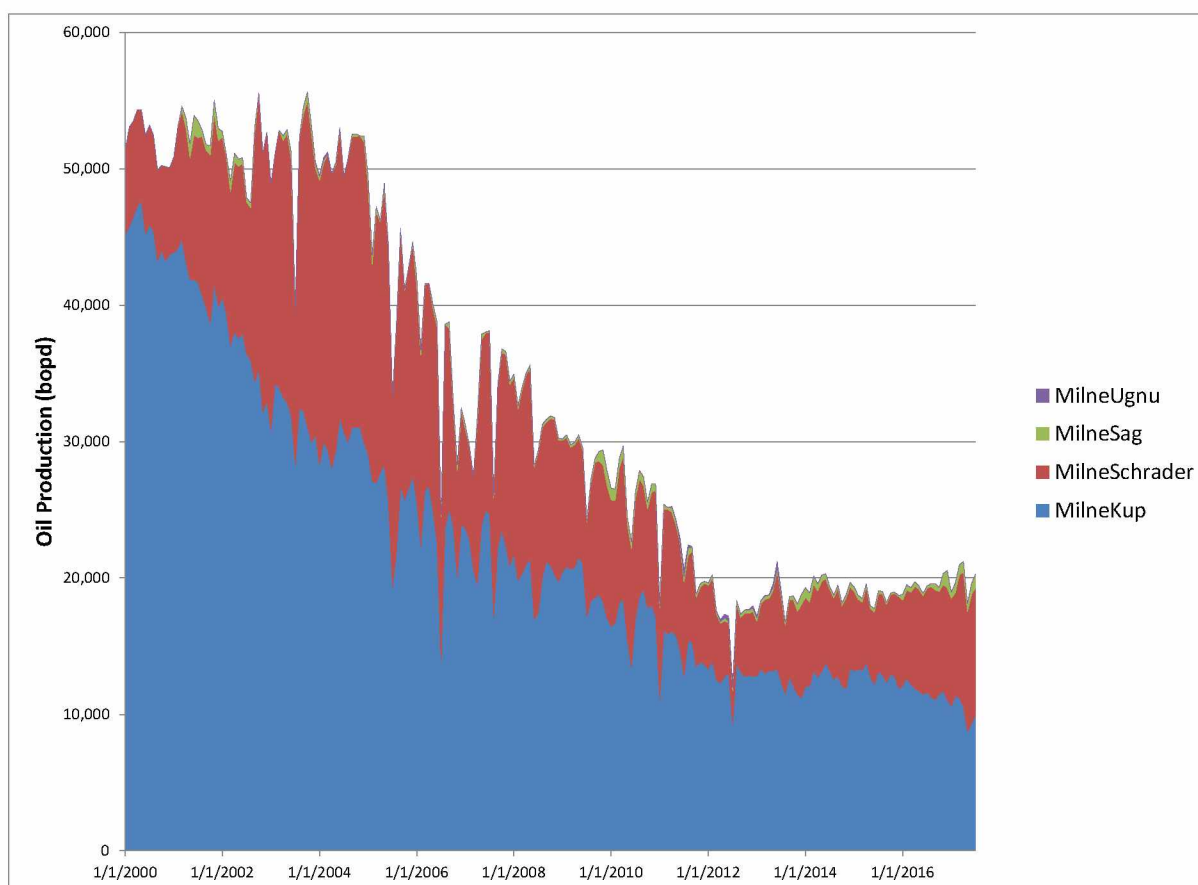


FIGURE 400: RECENT MILNE POINT UNIT PRODUCTION

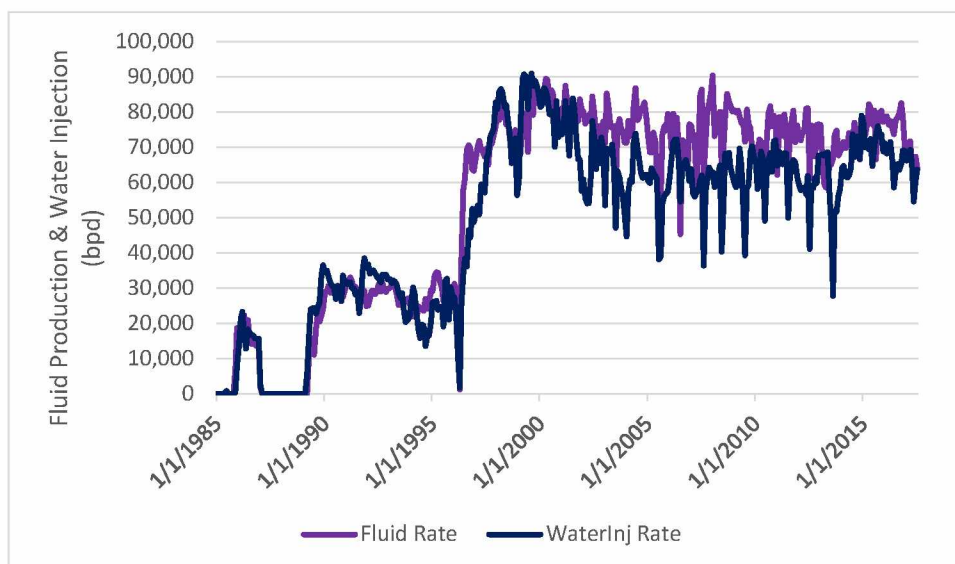


FIGURE 401: MILNE KUPARUK FLUID PRODUCTION AND WATER INJECTION

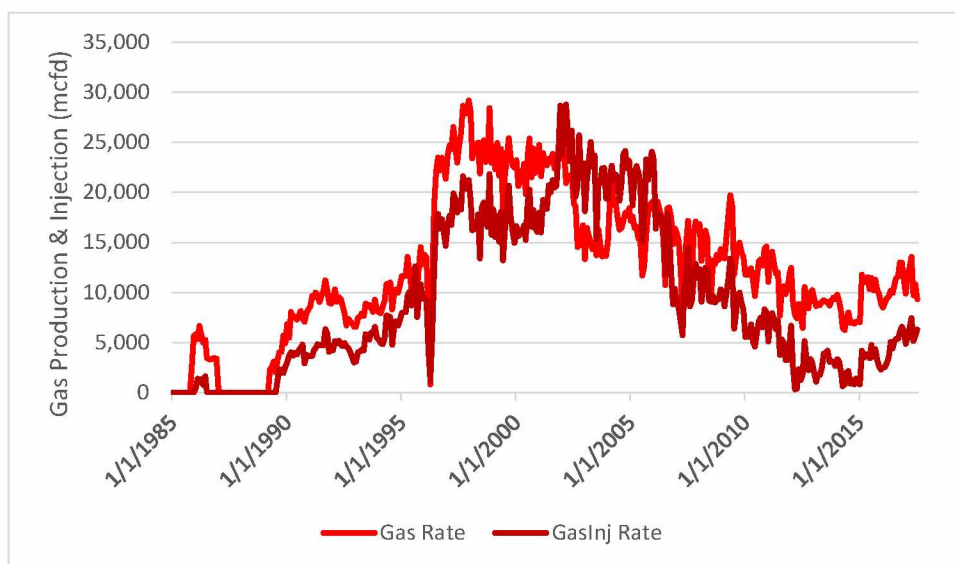


FIGURE 402: MILNE KUPARUK GAS PRODUCTION AND INJECTION

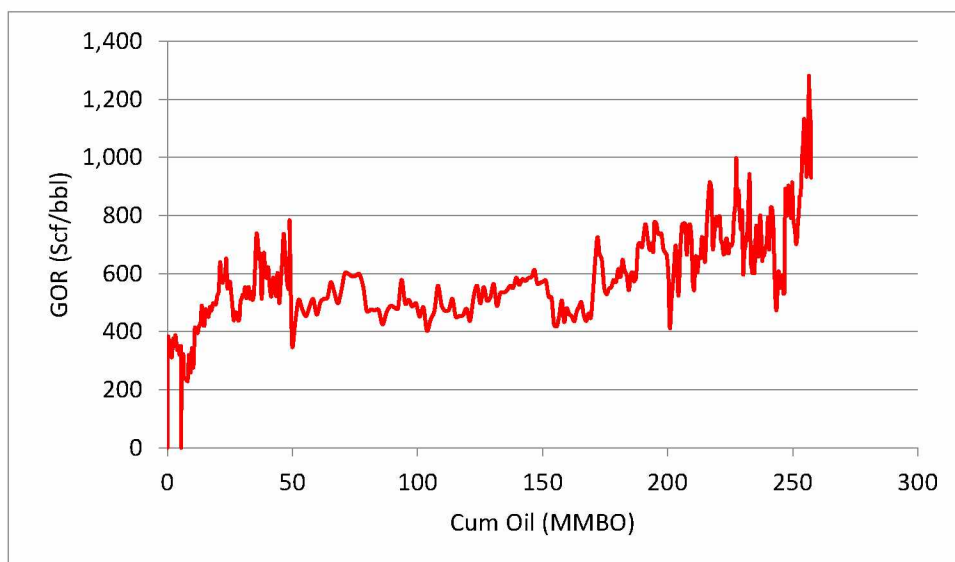


FIGURE 403: MILNE KUPARUK GAS OIL RATIO VS. CUM OIL

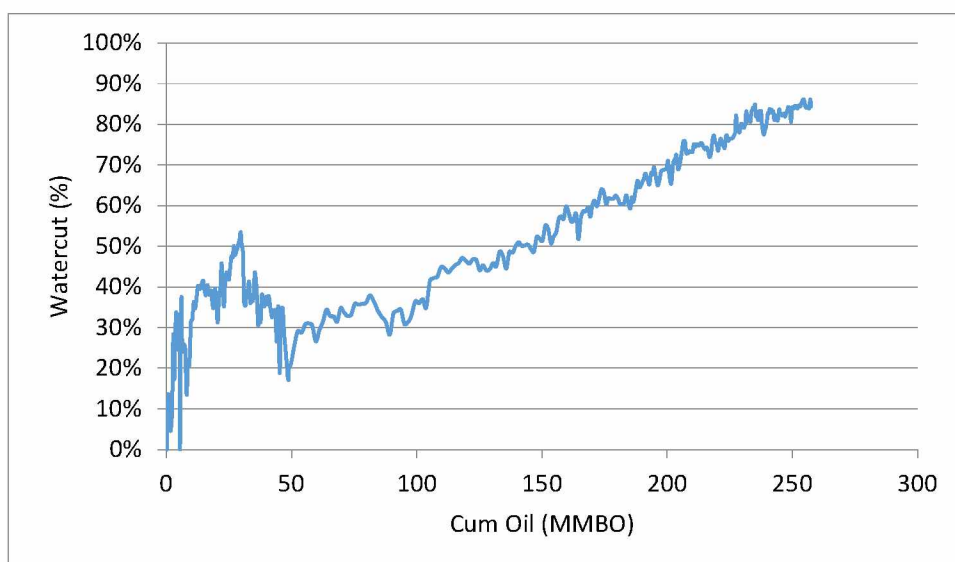


FIGURE 404: MILNE KUPARUK WATERCUT VS. CUM OIL

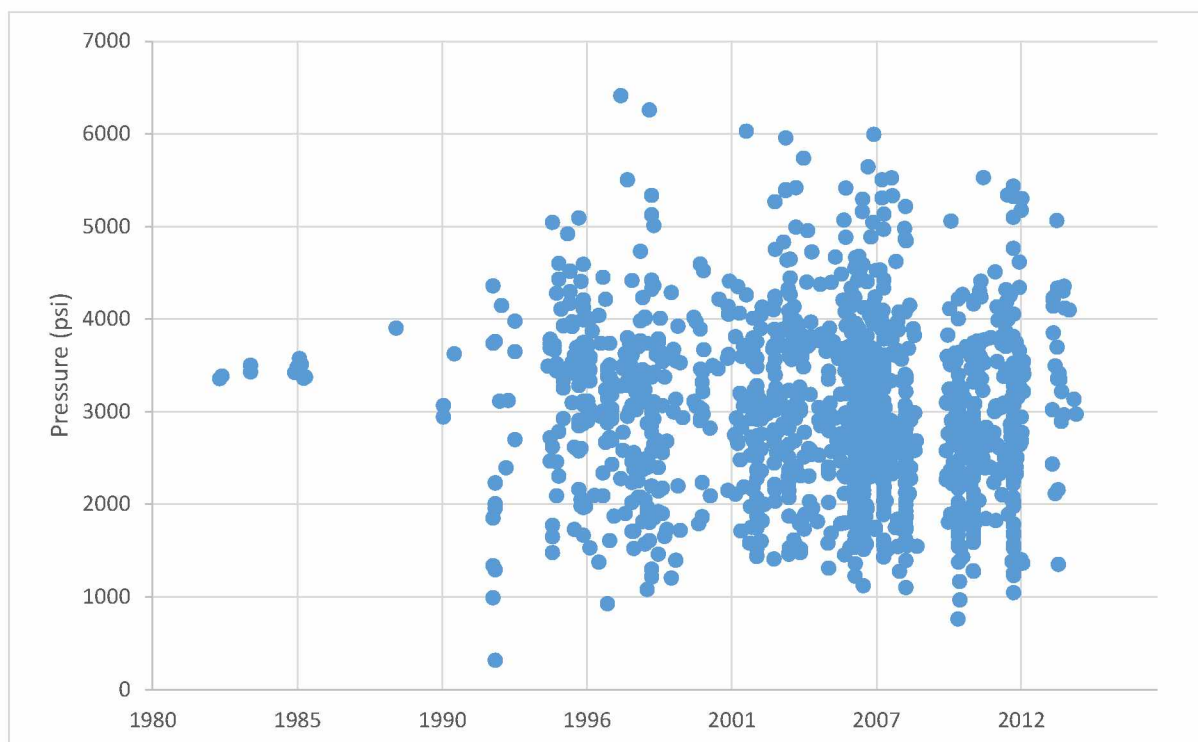


FIGURE 405: MILNE KUPARUK PRESSURES

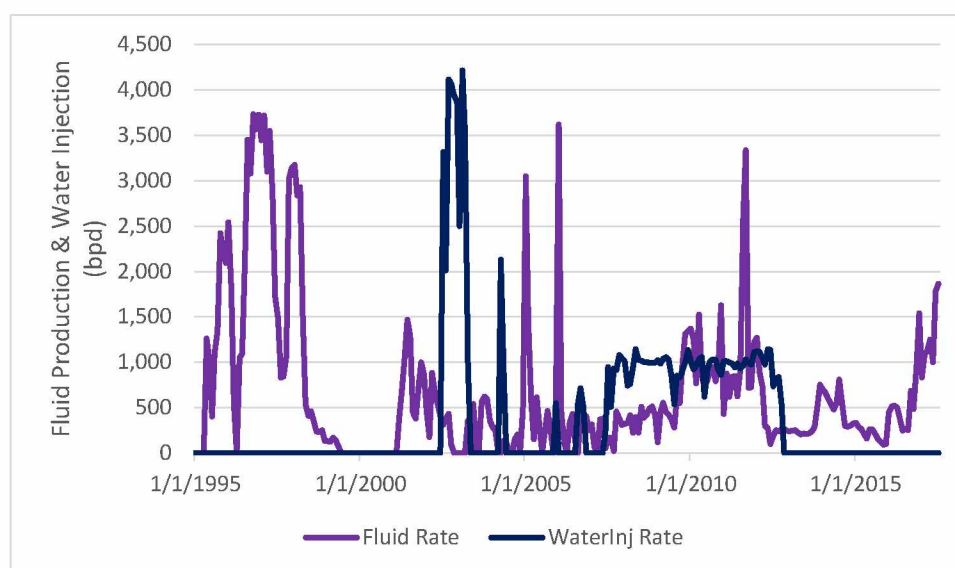


FIGURE 406: MILNE SAG FLUID PRODUCTION AND WATER INJECTION

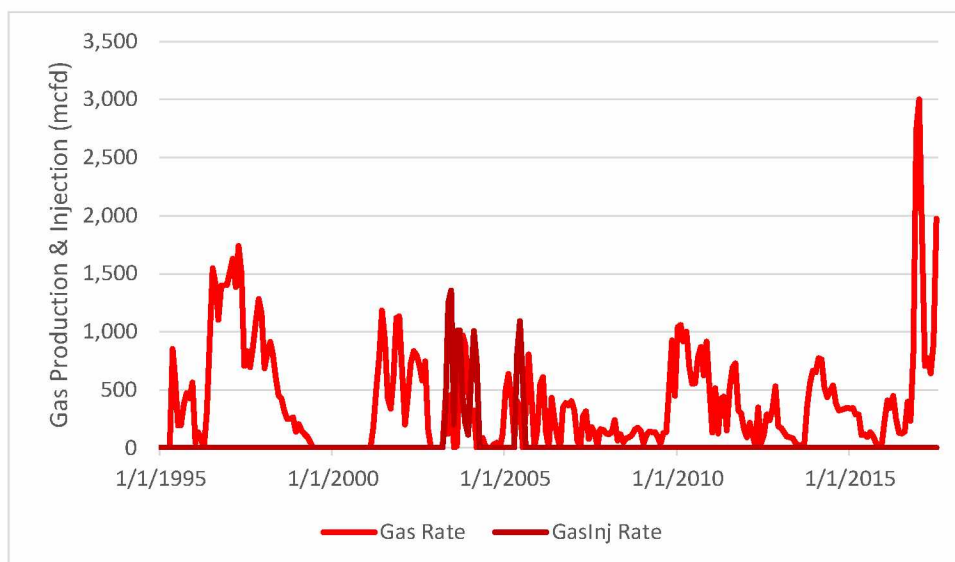


FIGURE 407: MILNE SAG GAS PRODUCTION AND INJECTION

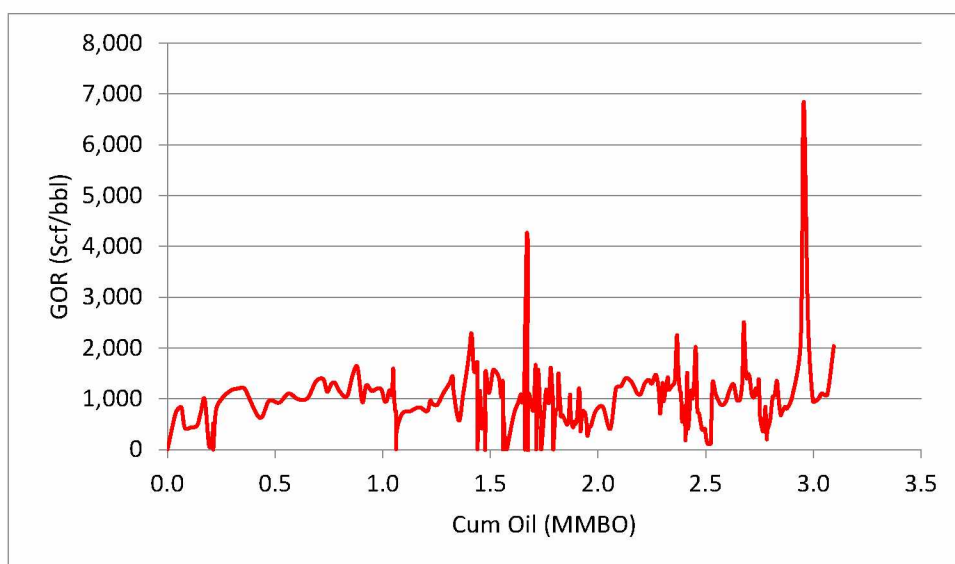


FIGURE 408: MILNE SAG GAS OIL RATIO VS. CUM OIL

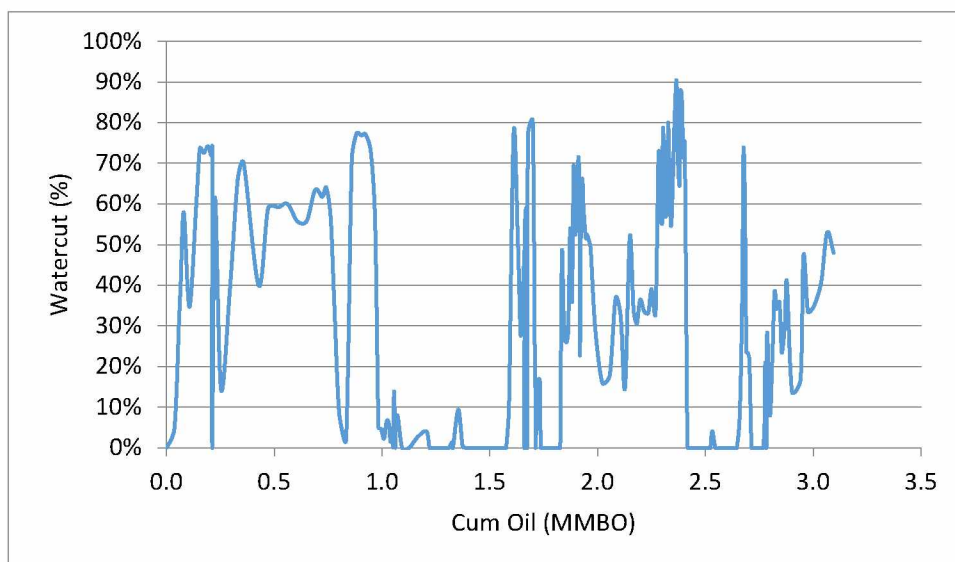


FIGURE 409: MILNE SAG WATERCUT VS. CUM OIL

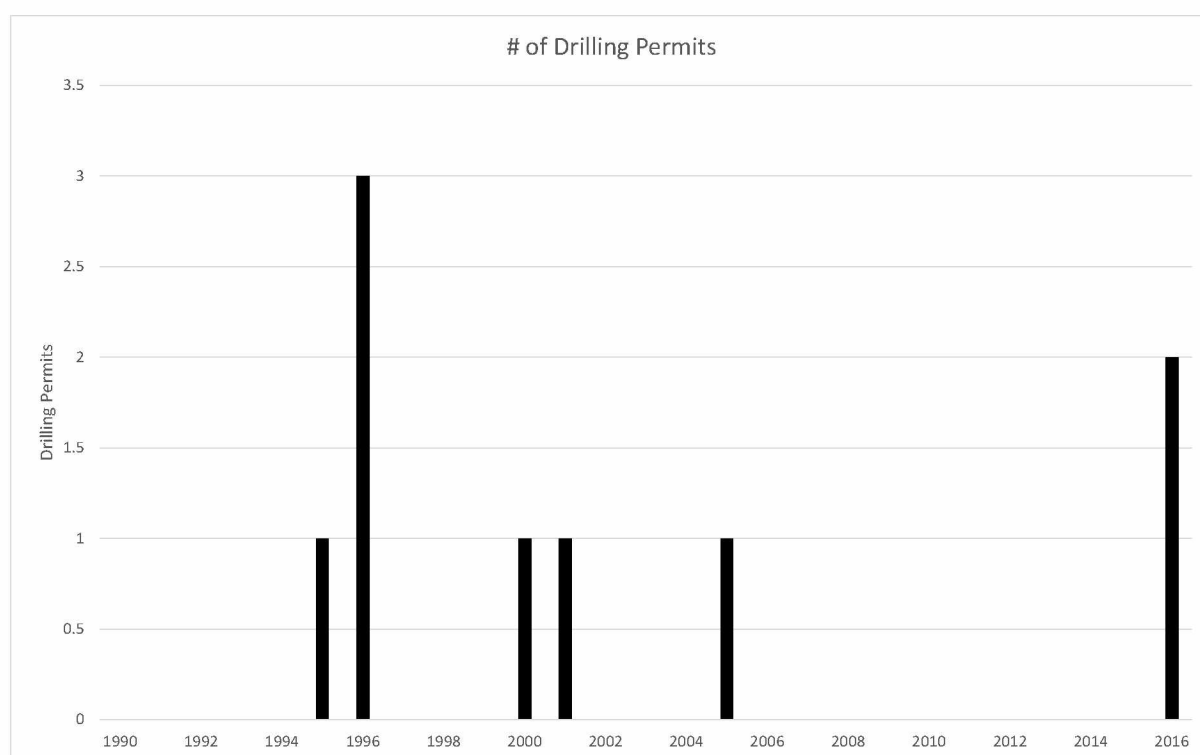


FIGURE 410: MILNE SAG DRILLING PERMITS BY YEAR



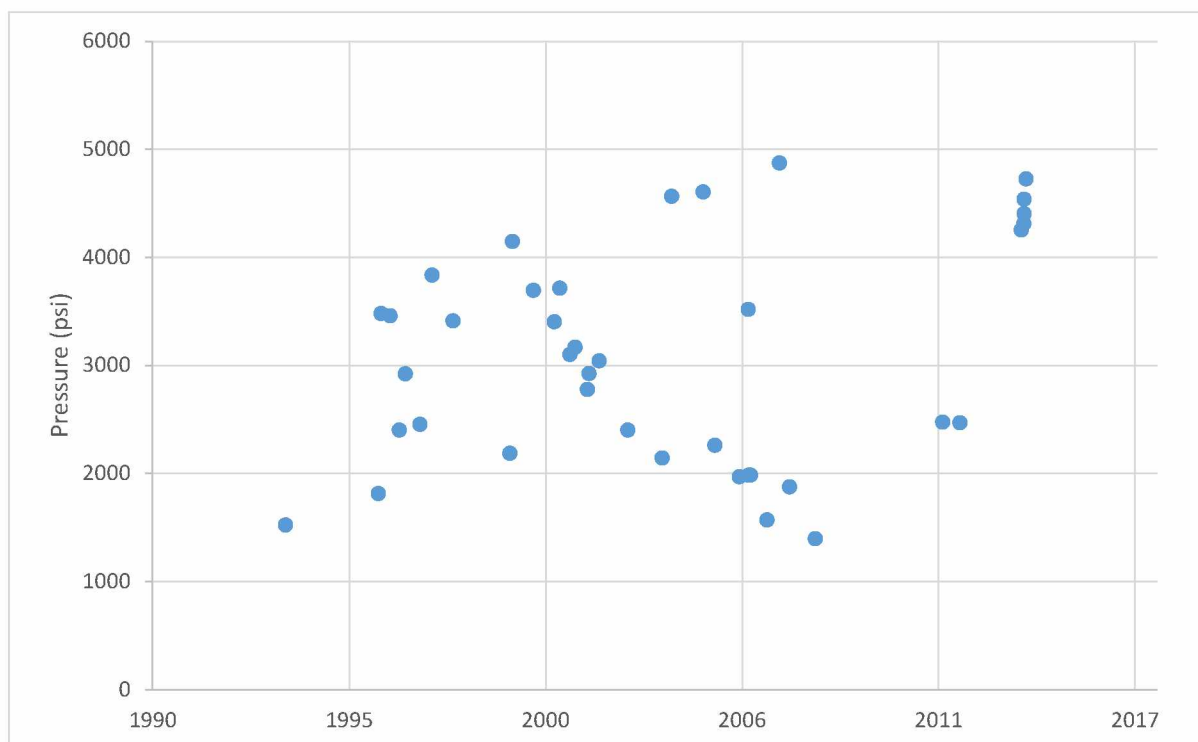


FIGURE 411: MILNE SAG PRESSURES

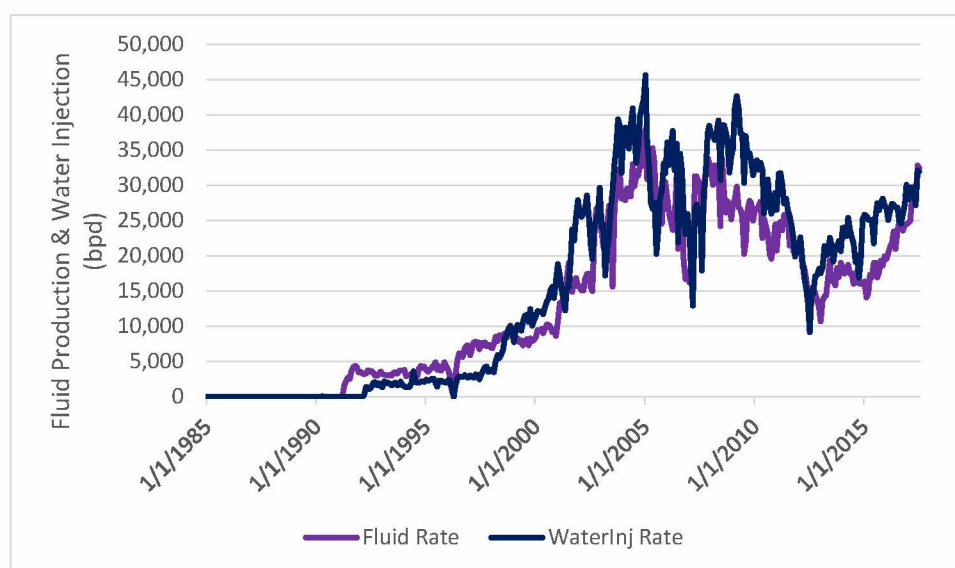


FIGURE 412: MILNE SCHRADER BLUFF FLUID PRODUCTION AND WATER INJECTION

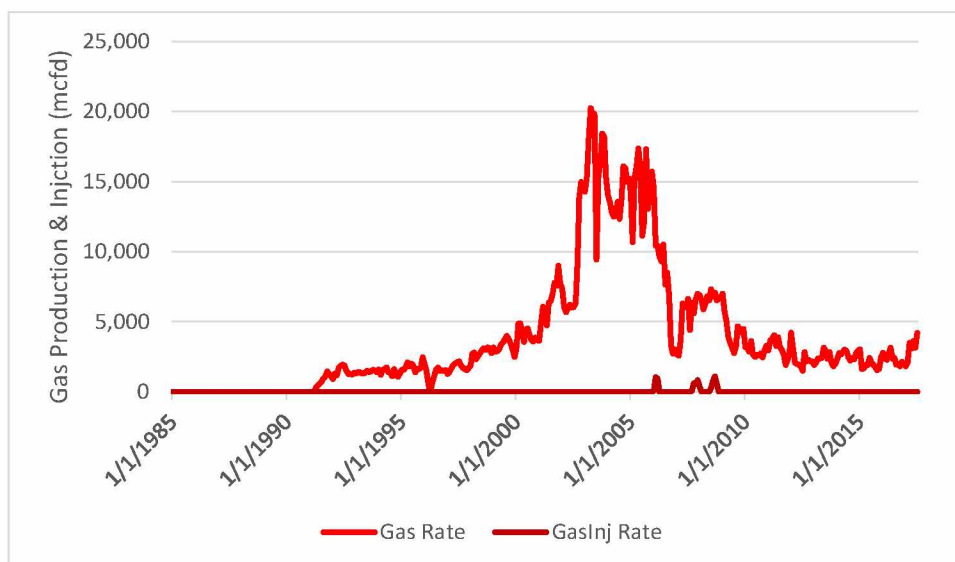


FIGURE 413: MILNE SCHRADER BLUFF GAS PRODUCTON AND INJECTION FIX ALL CHARTS LIKE THIS

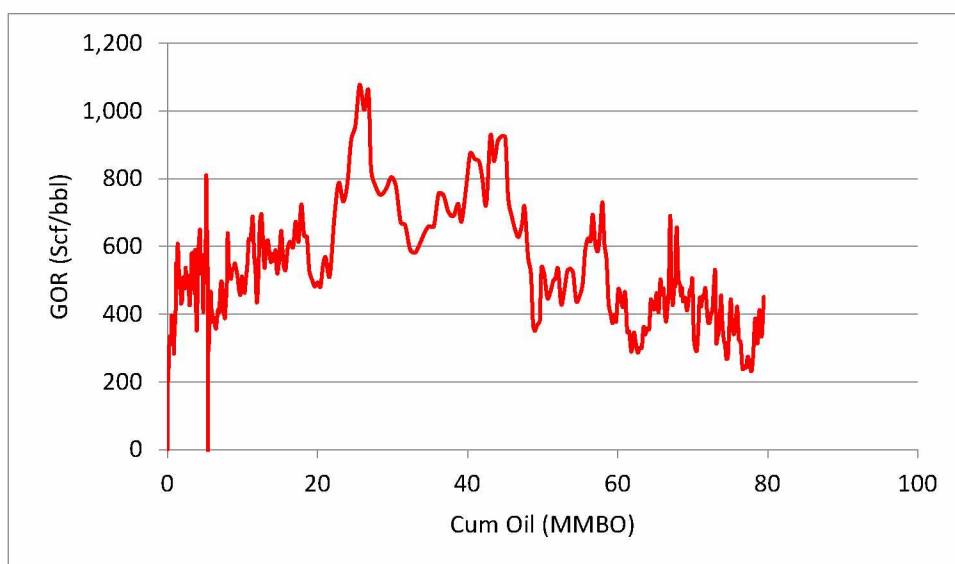


FIGURE 414: MILNE SCHRADER BLUFF GAS OIL RATIO VS. CUM OIL

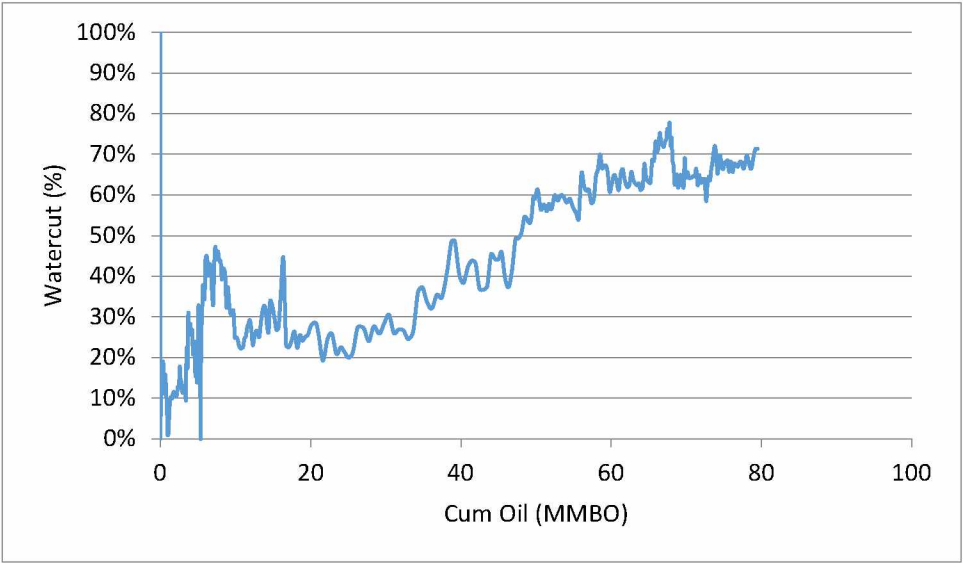


FIGURE 415: MILNE SCHRADER BLUFF WATERCUT VS. CUM OIL

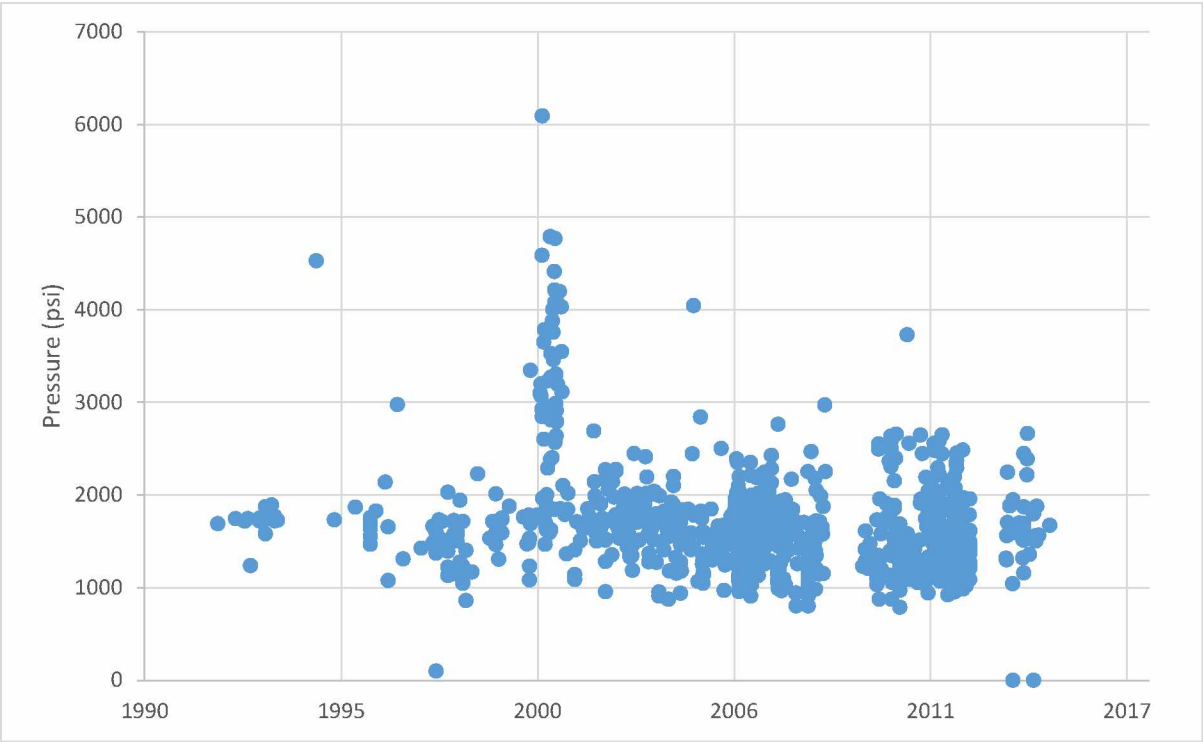


FIGURE 416: MILNE SCHRADER BLUFF PRESSURES

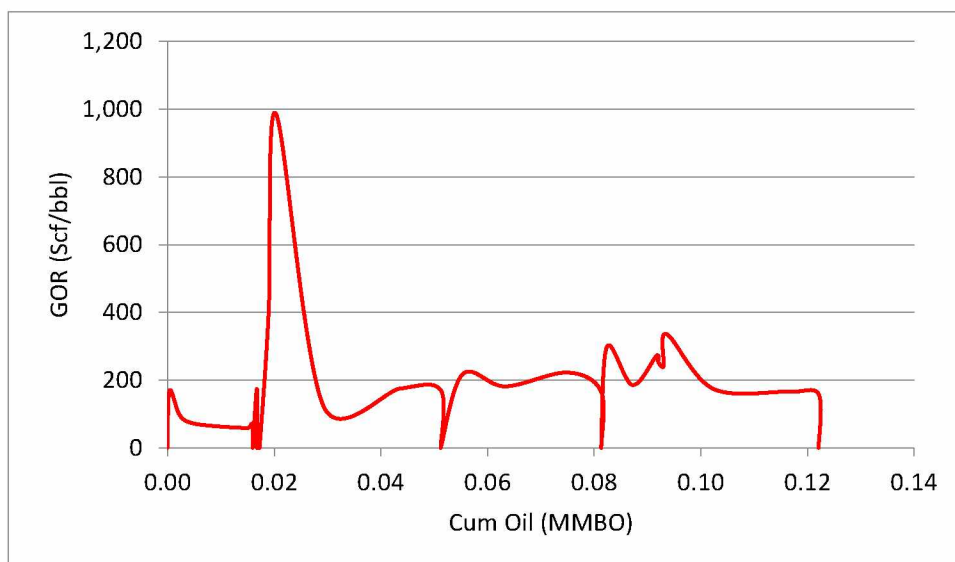


FIGURE 417: MILNE UGNU GAS OIL RATIO VS. CUM OIL

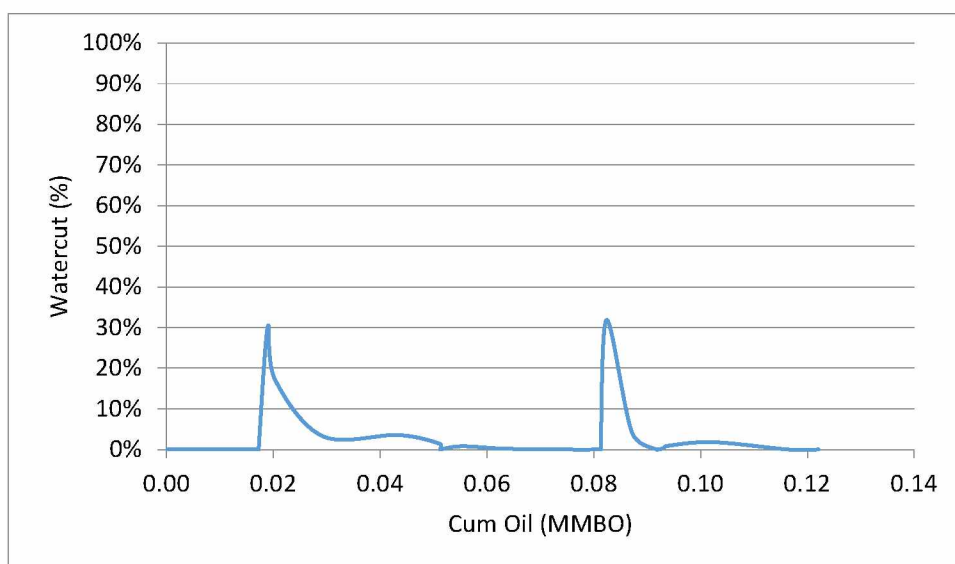


FIGURE 418: MILNE UGNU WATERCUT VS. CUM OIL

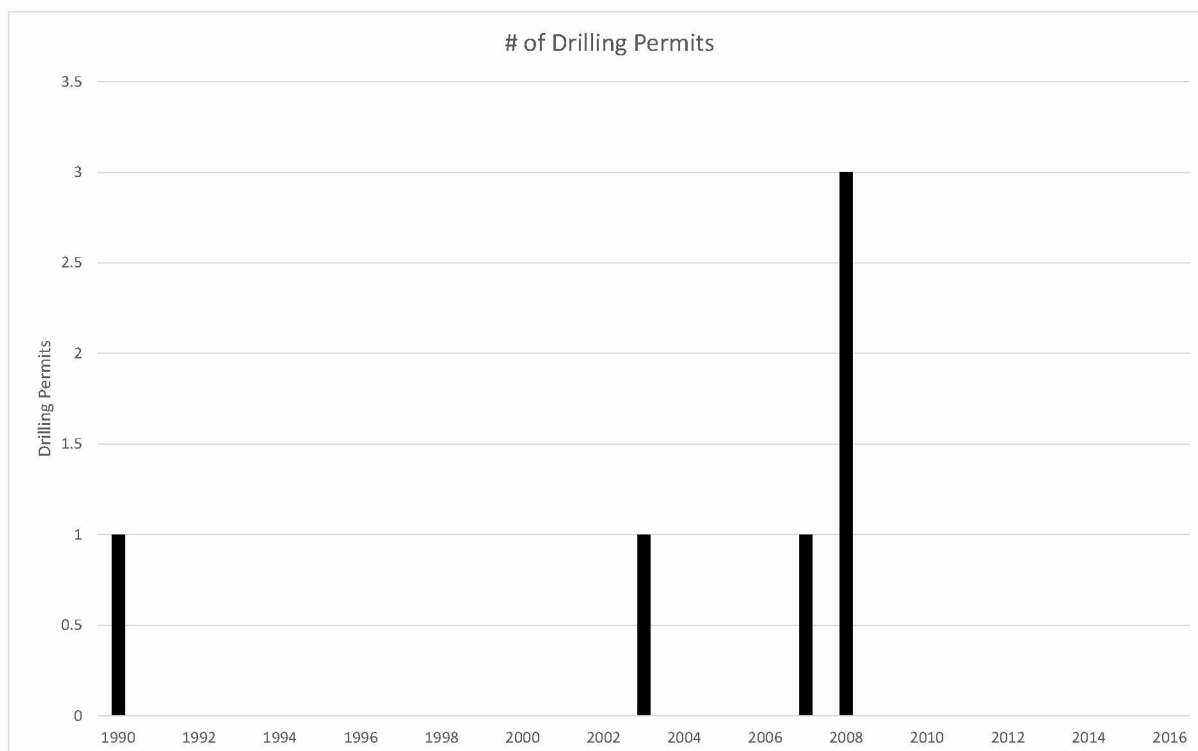


FIGURE 419: MILNE UGNU DRILLING PERMITS BY YEAR

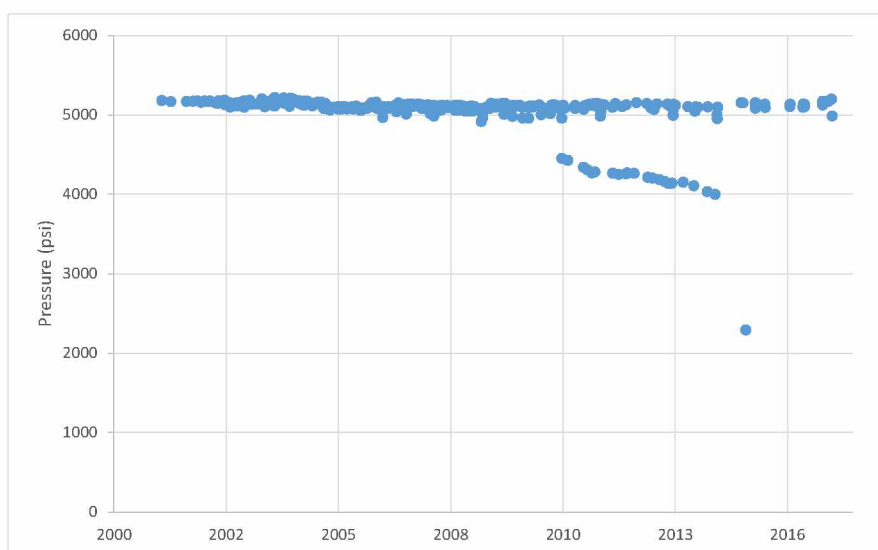


FIGURE 420: NORTHSTAR PRESSURES

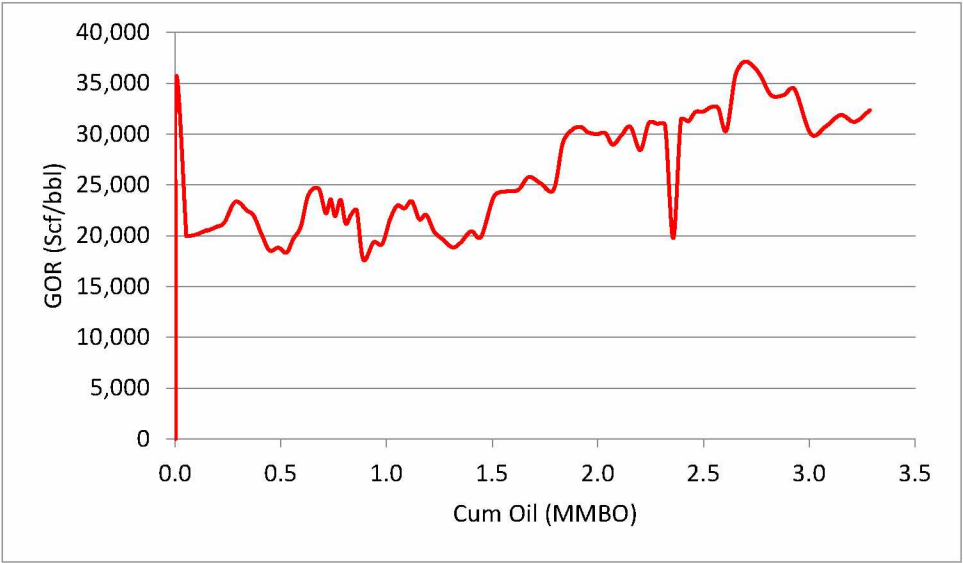


FIGURE 421: NORTHSTAR KUPARUK GAS OIL RATIO VS. CUM OIL

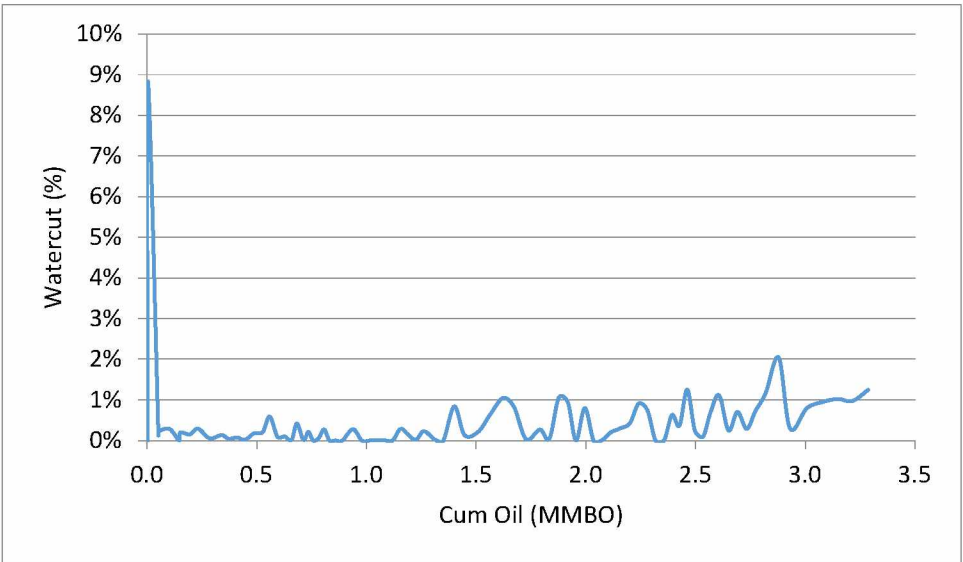


FIGURE 422: NORTHSTAR KUPARUK WATERCUT VS. CUM OIL



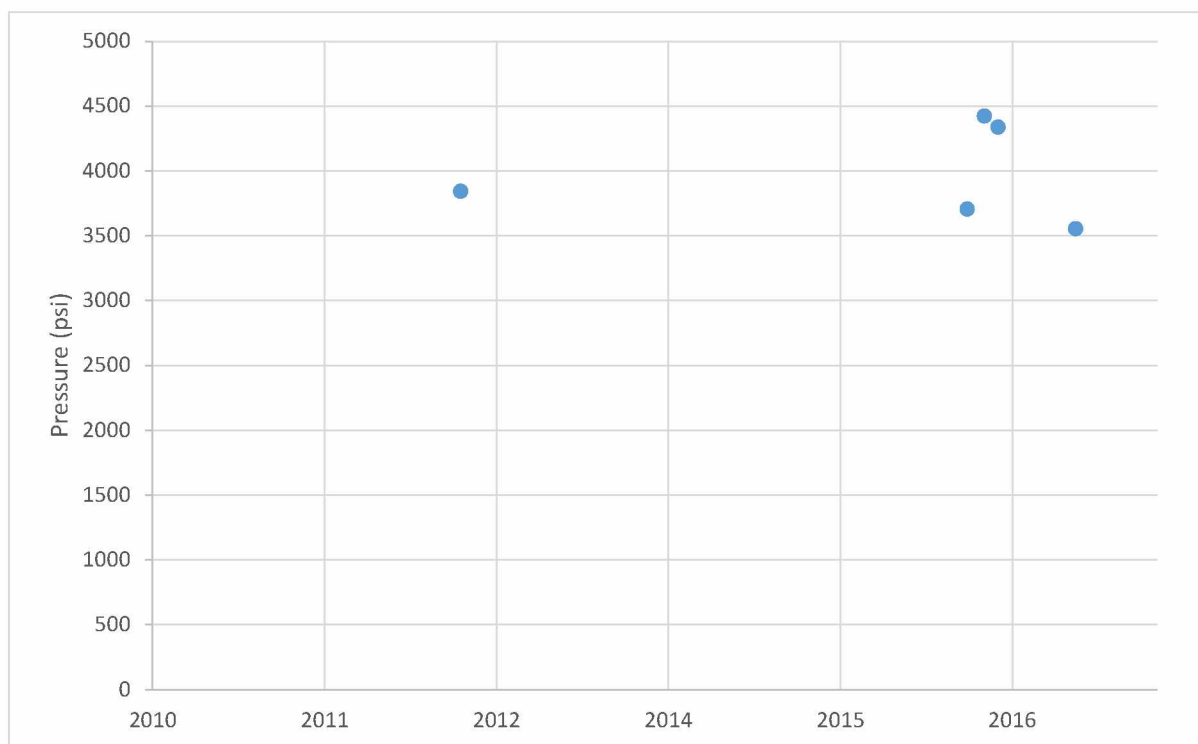


FIGURE 423: NORTHSTAR KUPARUK PRESSURES

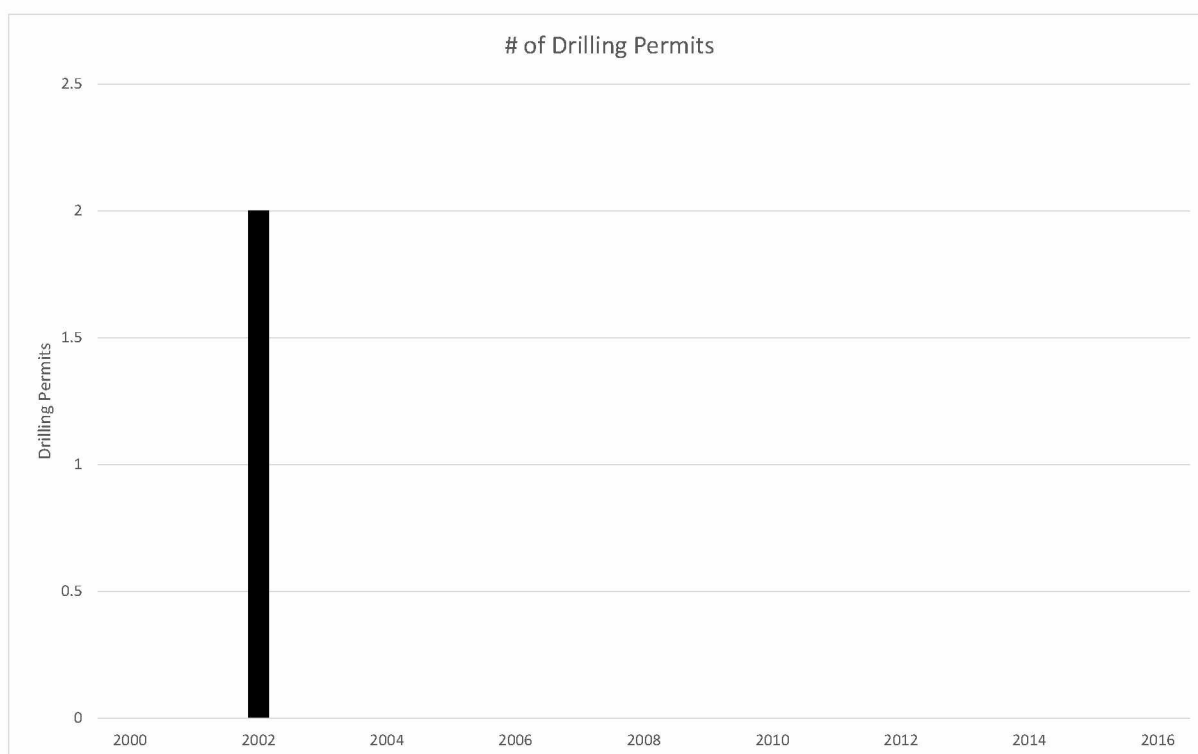


FIGURE 424: NORTHSTAR KUPARUK DRILLING PERMITS BY YEAR

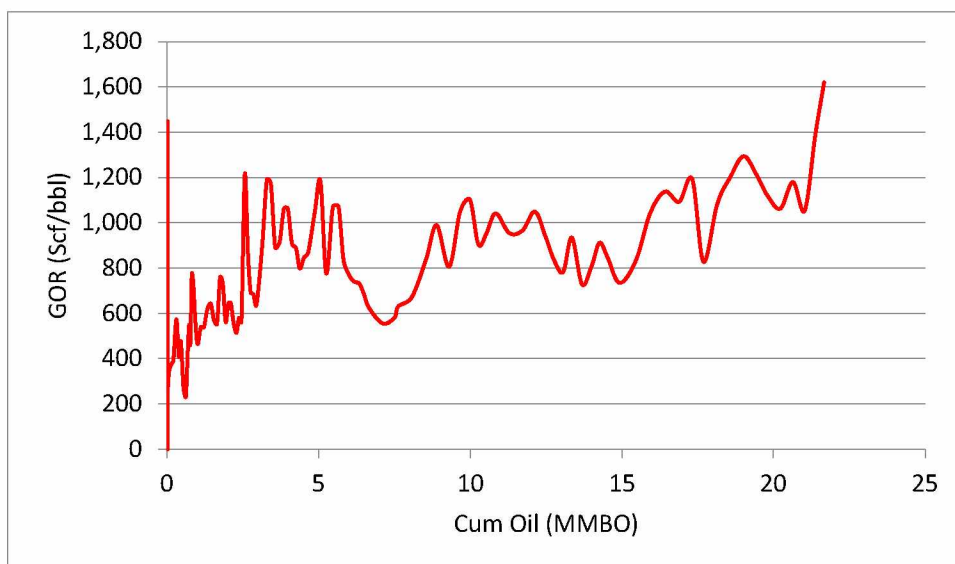


FIGURE 425: OOOGURUK NUIQSUT GAS OIL RATIO VS. CUM OIL

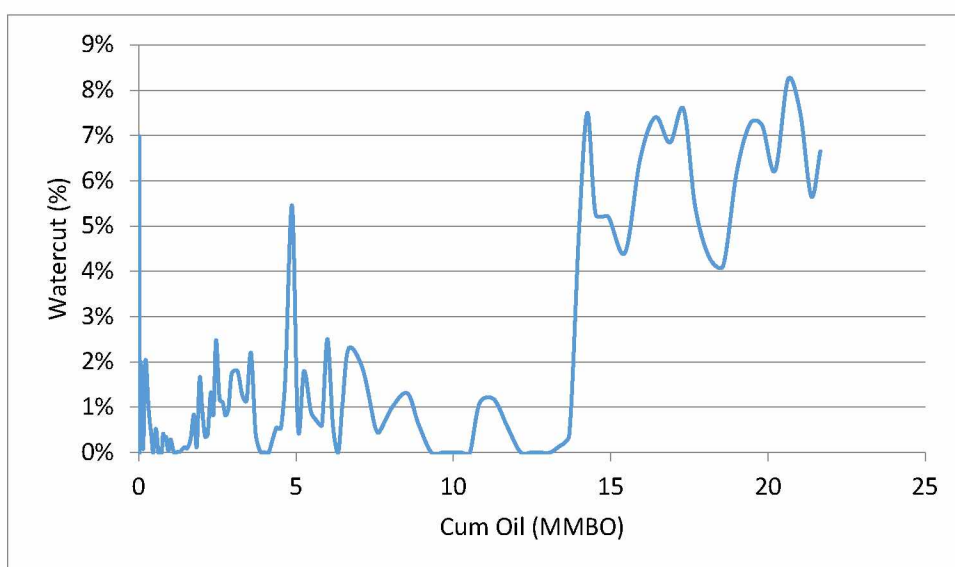


FIGURE 426: OOOGURUK NUIQSUT WATERCUT V.S CUM OIL

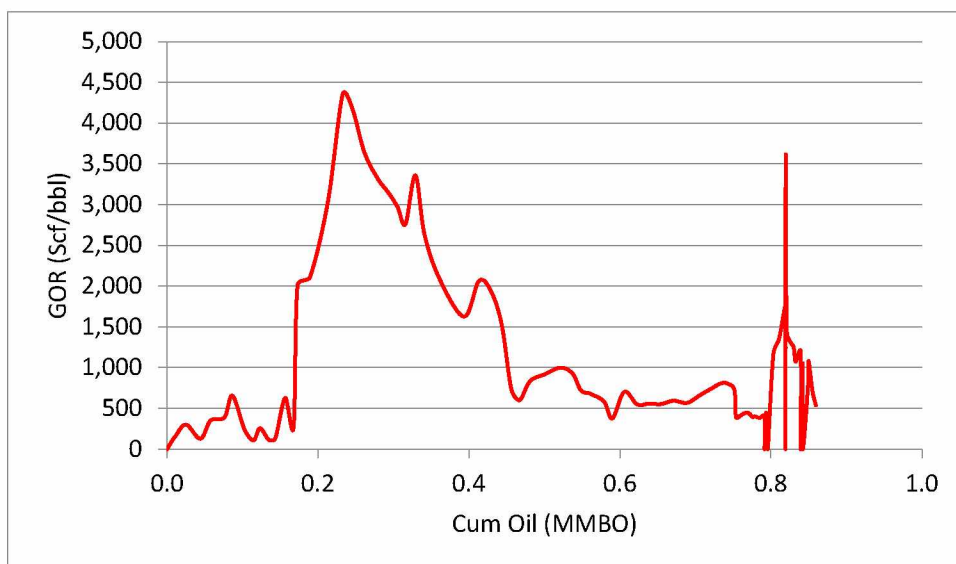


FIGURE 427: OOOGURUK TOROK GAS OIL RATIO VS. CUM OIL

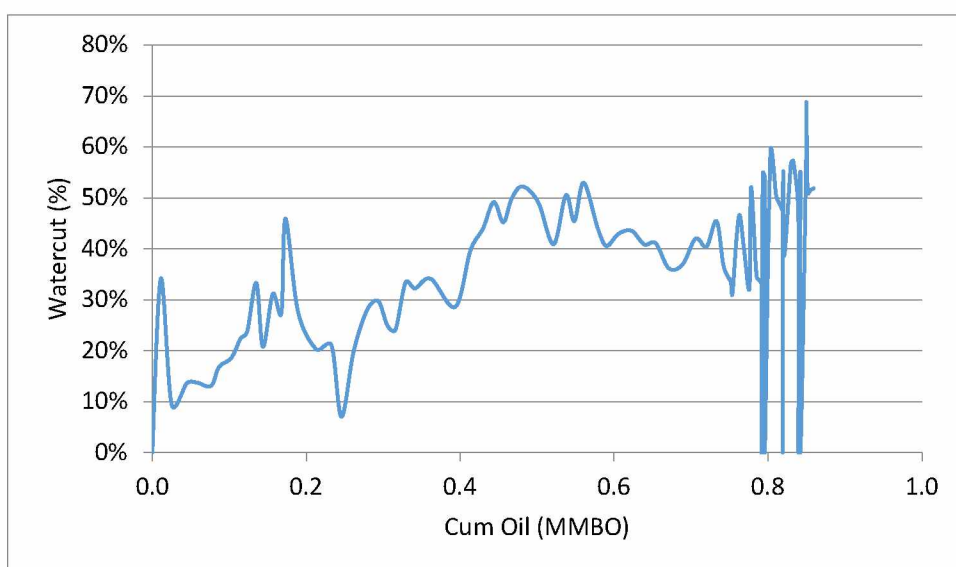


FIGURE 428: OOOGURUK TOROK WATERCUT VS. CUM OIL

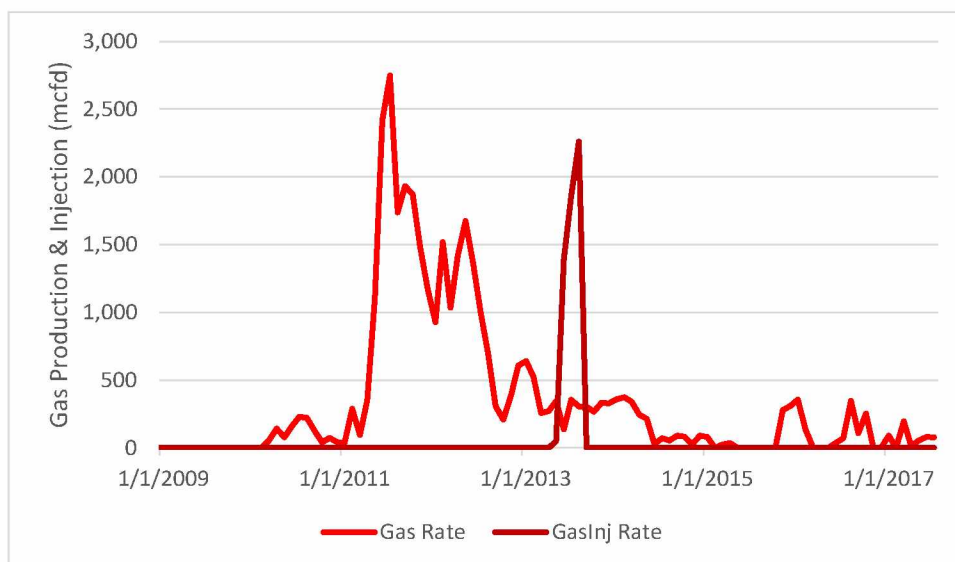


FIGURE 429: OOOGURUK TOROK GAS PRODUCTION AND INJECTION

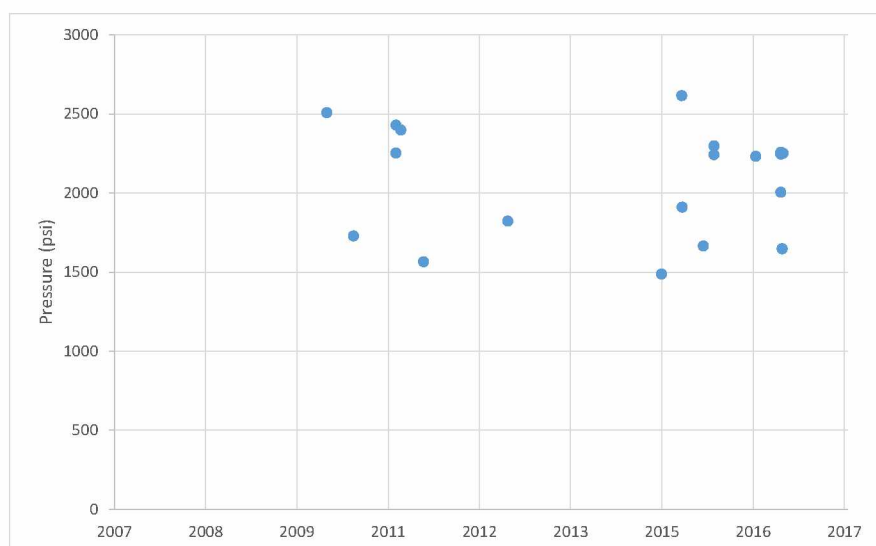


FIGURE 430: OOOGURUK TOROK PRESSURES

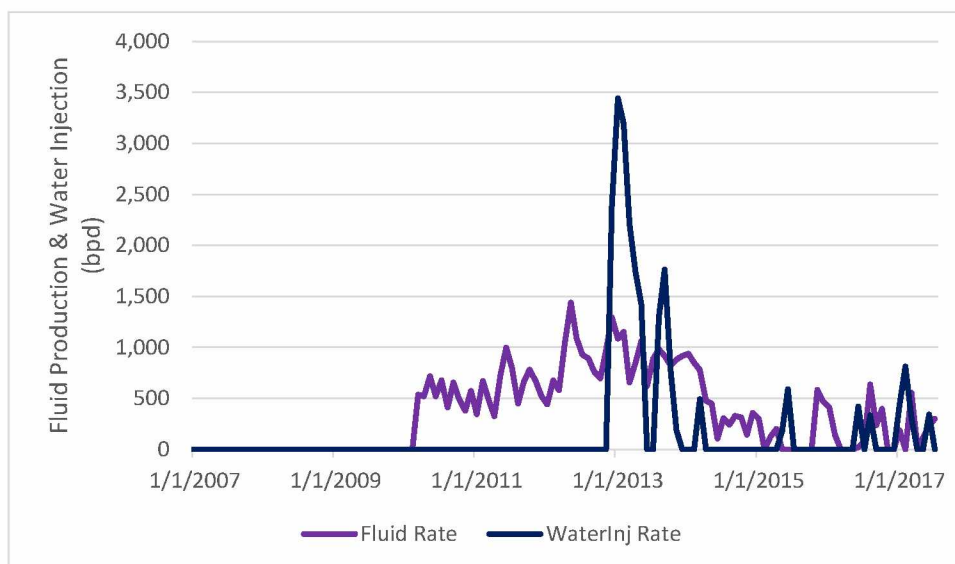


FIGURE 431: OOOGURUK TOROK FLUID PRODUCTION AND WATER INJECTIO RATE

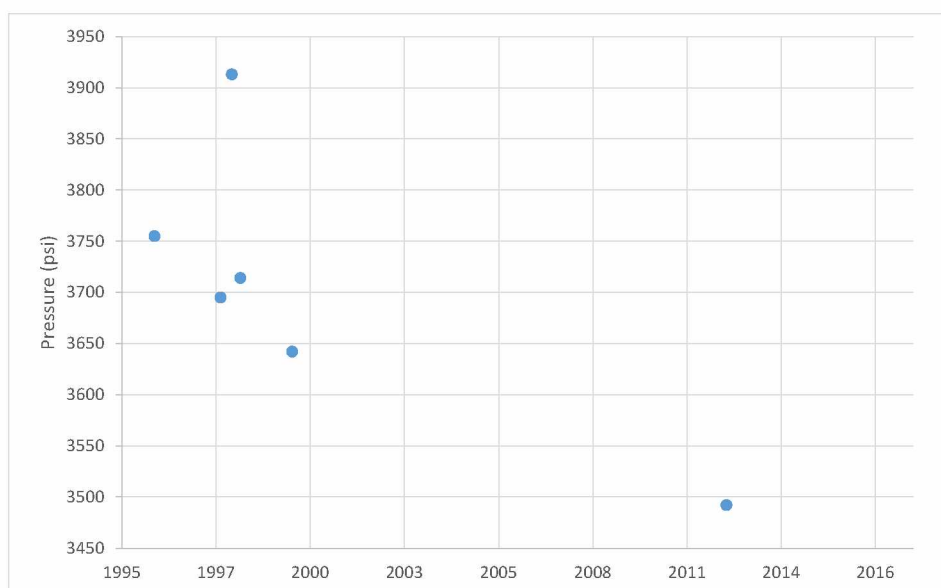


FIGURE 432: NORTH PRUDHOE BAY PRESSURES

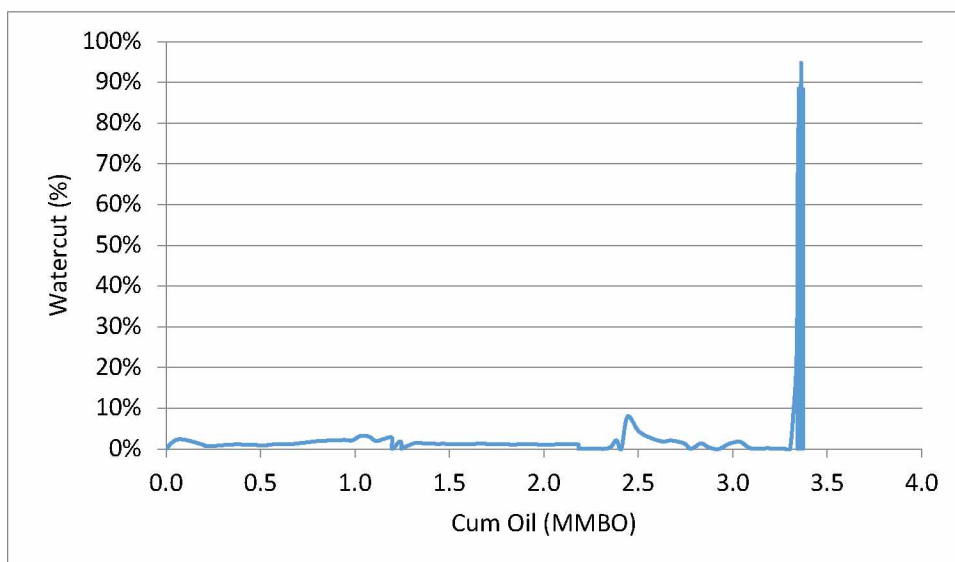


FIGURE 433: WEST BEACH WATERCUT VS CUM OIL

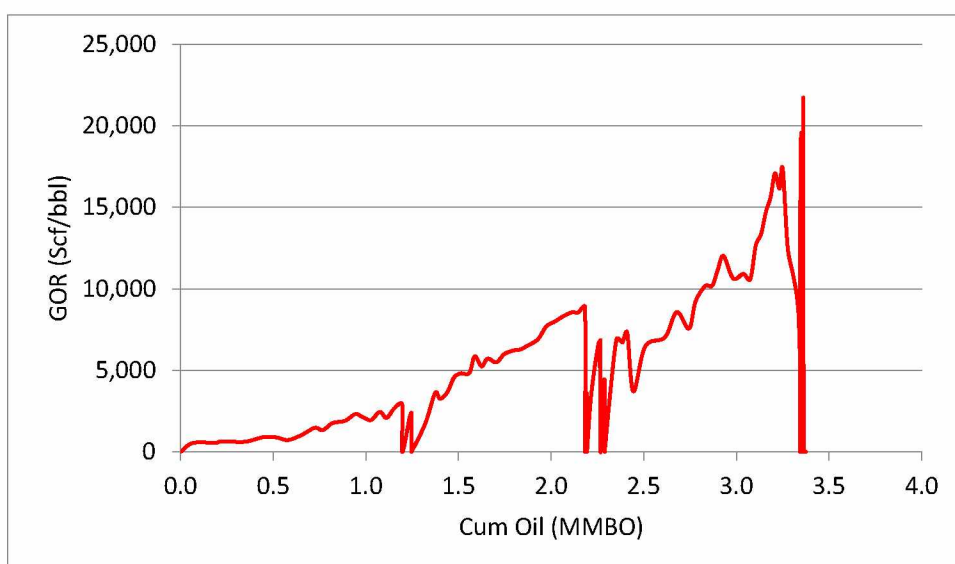


FIGURE 434: WEST BEACH GAS OIL RATIO VS. CUM OIL

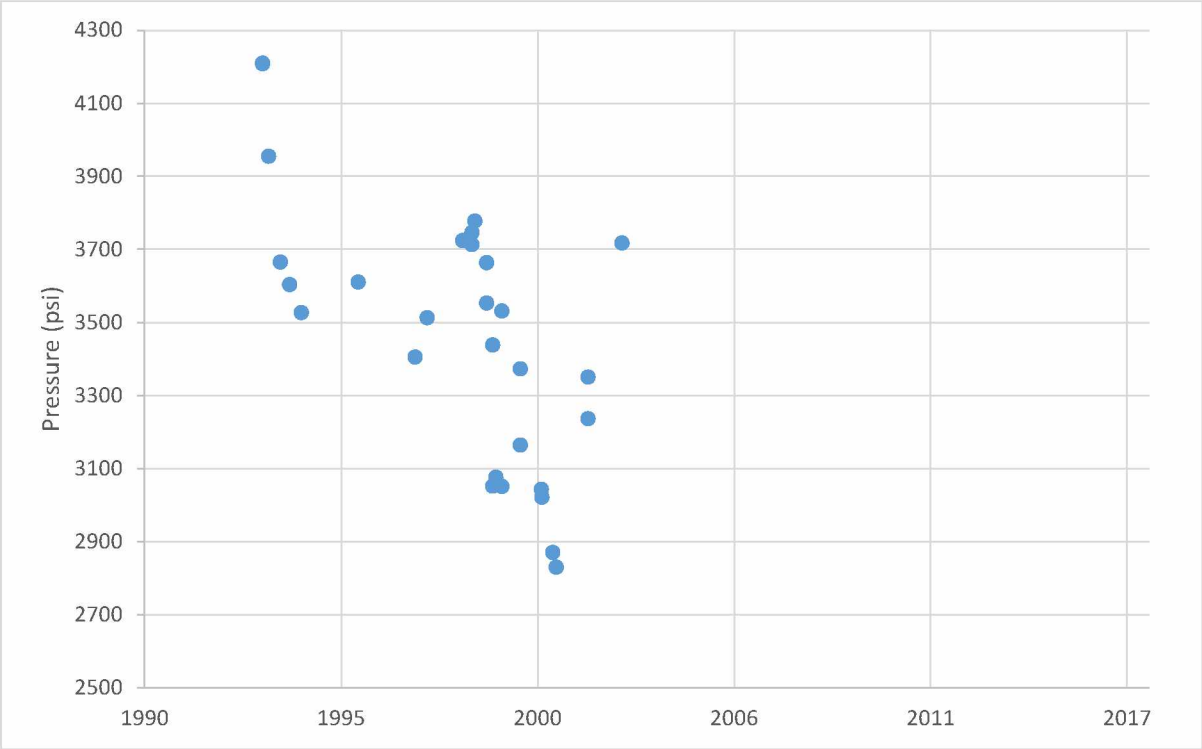


FIGURE 435: WEST BEACH PRESSURES

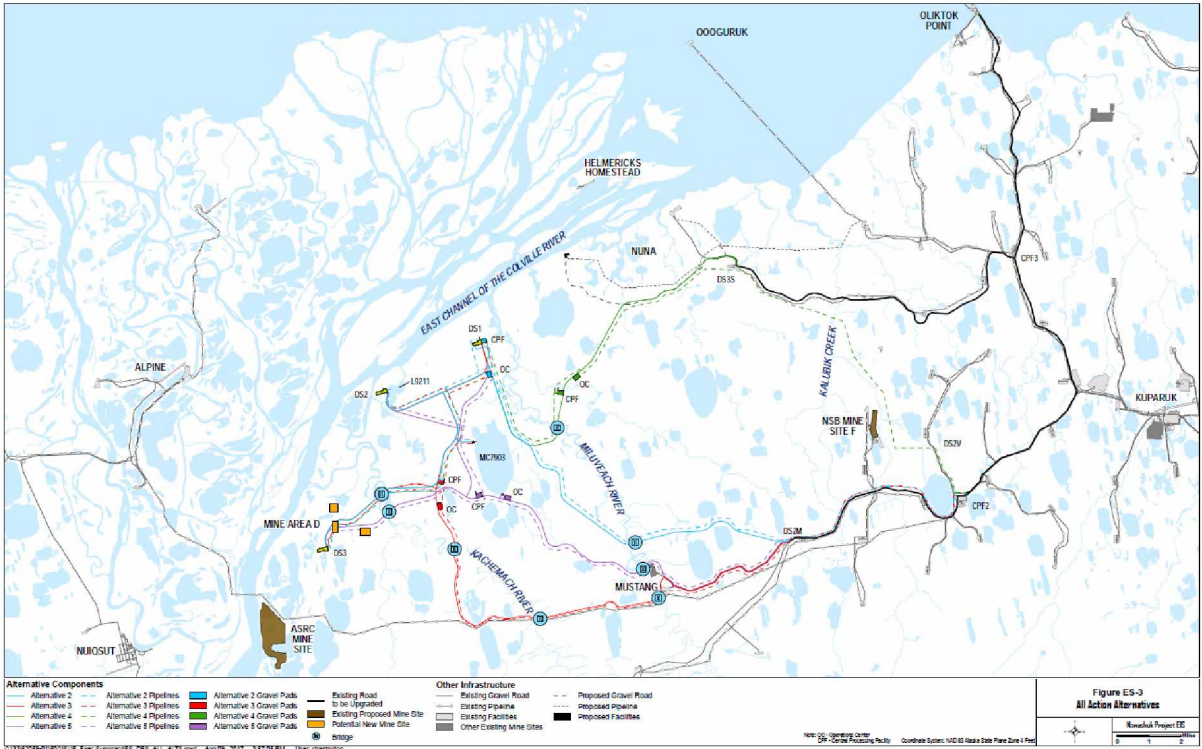


FIGURE 436: PIKKA DEVELOPMENT MAP WITH ALTERNATIVE ROADS (UNITED STATES ARMY CORPS OF ENGINEERS, 2017)



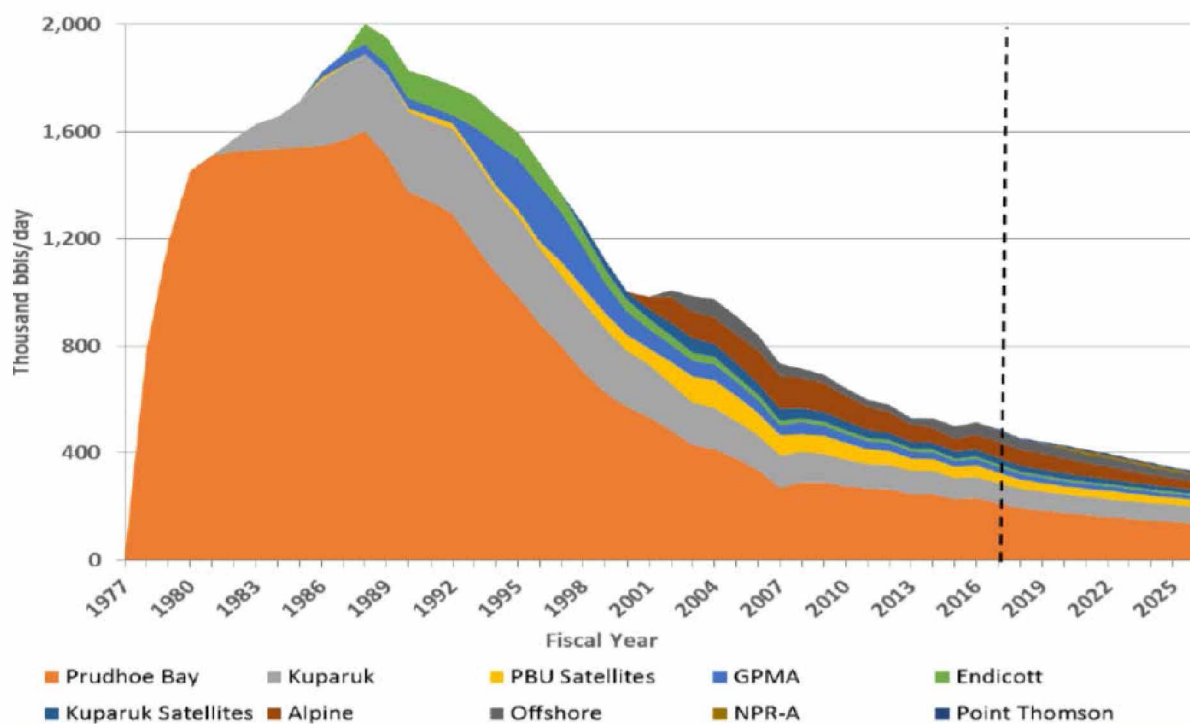


FIGURE 437: DEPRATMENT OF REVENUE 10 YEAR FORECAST (UMEKWE, 2017)

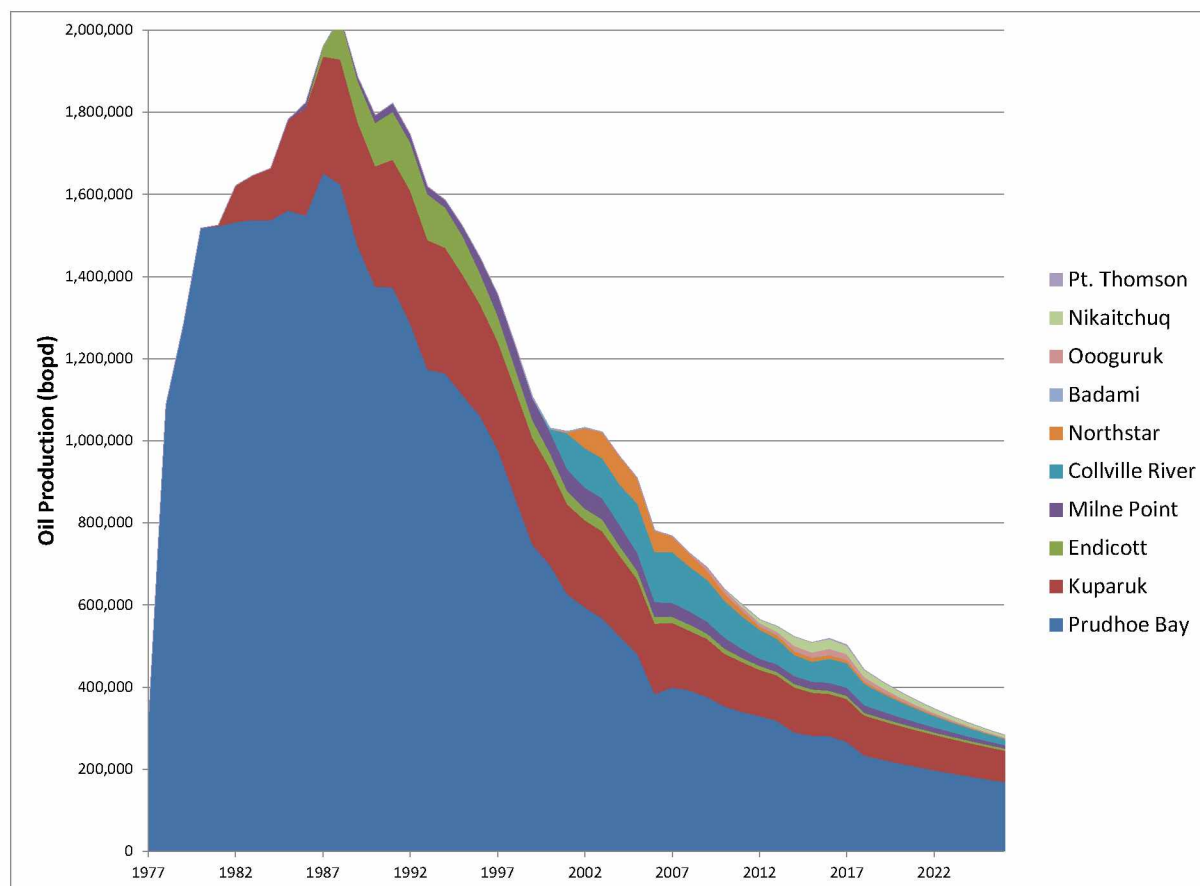


FIGURE 438: COMPARATIVE CHART TO DOR 10 YEAR PRODUCTION FORECAST

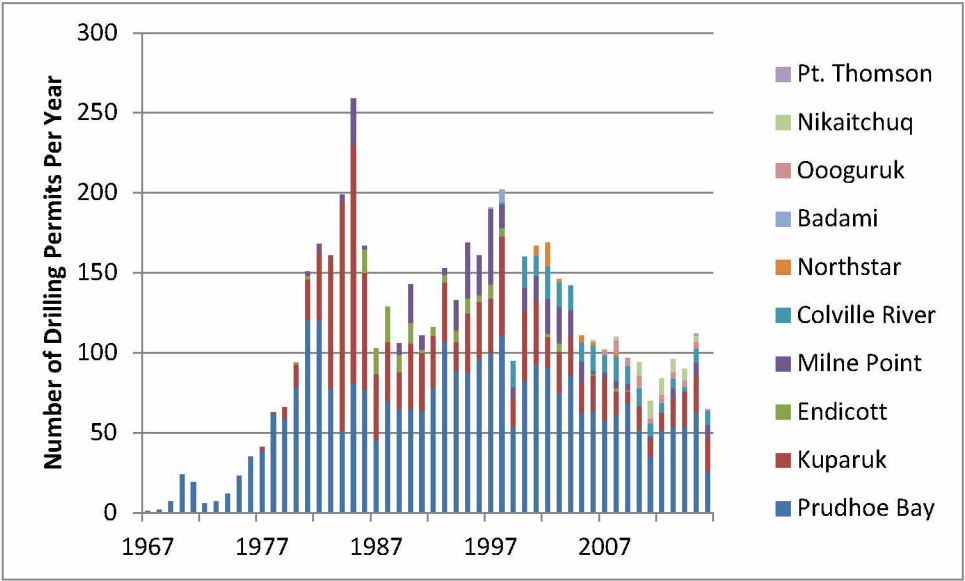


FIGURE 439: NORTH SLOPE DRILLING ACTIVITY BY YEAR

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